DIRECT TESTIMONY OF

JAMES E. SWAN, IV

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2012-218-E

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is James E. Swan, IV. My business address is 220 Operation Way, Cayce, South Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by SCANA Services, Inc. and serve as the Controller of SCANA Corporation and its subsidiaries ("SCANA"), including South Carolina Electric & Gas Company (the "Company" or "SCE&G").

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I received a Bachelor of Science degree in Accounting from Clemson University, cum laude, in May of 1982. In June 1982, I joined the public accounting firm of Touche Ross & Co. as an auditor, and I left the firm as a senior accountant in June 1986 to become the Controller of Nautilus Sports/Medical Industries, Inc. In December of 1987, I left Nautilus and returned to the Touche Ross accounting firm as an audit manager. While at Touche Ross, which later became Deloitte & Touche, I was responsible for the performance of audit and related services for clients in the utilities, manufacturing and distribution, healthcare, telecommunications, and technology industries. I later served in a risk management role in Deloitte & Touche's National Office, and I also devoted a significant amount of time to resolution of technical accounting issues and to serving Securities and Exchange Commission registrants. I left the firm as an audit partner in August 2000 to join SCANA as an assistant controller, and I became SCANA's and SCE&G's Controller in the Spring of 2002. I am a certified public accountant in South Carolina and North Carolina, and I am a member of the American Institute of Certified Public Accountants.

Q. HAVE YOU EVER TESTIFIED BEFORE THIS COMMISSION IN THE PAST?

A. Yes. I have testified before the Public Service Commission of South Carolina (the "Commission") in several past proceedings.

Q. PLEASE DESCRIBE THE SCOPE OF THE TESTIMONY YOU ARE PRESENTING IN THIS CASE.

A. In connection with its Application for Adjustments and Increases in Electric Rates and Charges ("Application"), the Company included certain exhibits containing financial information. In this testimony, I discuss a number of those exhibits and ask the Commission to incorporate by reference the Application into the record of these hearings. The purpose of my testimony is to describe each of these exhibits and certain other accounting and financial information in support of the Company's Application.

Q. HOW ARE THE BOOKS AND RECORDS OF THE COMPANY MAINTAINED?

A. The books and records of the Company are maintained in accordance with accounting principles generally accepted in the United States and with the Uniform System of Accounts for major utilities as prescribed by the Federal Energy Regulatory Commission ("FERC"). This Uniform System of Accounts has been adopted by the Commission and is followed by major utilities subject to its jurisdiction. Compliance with generally accepted accounting principles and the Uniform System of Accounts is necessary in order to provide consistent and pertinent financial information to the general public, investors, regulators, and the financial community.

Q. WHAT STEPS DOES THE COMPANY TAKE TO ENSURE THAT ITS BOOKS AND RECORDS ARE ACCURATE AND COMPLETE?

A. The Company maintains and relies upon an extensive system of internal accounting controls, audits by both internal and external auditors, and financial oversight by the Audit Committee of SCANA's Board of Directors. The system of internal accounting controls is designed to provide reasonable assurance that all transactions are properly recorded in the books and records and that assets are protected against loss or unauthorized use. The Company's system of internal accounting controls has long been reviewed annually by our independent auditors in connection with their financial statement audits. In addition, Section 404 of the Sarbanes Oxley Act of 2002 requires that the Company's internal control system be subjected to an even more thorough analysis. Each year, management documents SCANA's significant accounting processes and thoroughly tests the key internal accounting controls, while our external auditors report on their own independent audit of those controls. No material weaknesses in our internal controls have been identified as a result of either the management assessment process or the independent audits.

Q. PLEASE DESCRIBE EXHIBIT NO. __ (JES-l) WHICH IS ALSO EXHIBIT NO. C-1 OF THE APPLICATION.

A. Exhibit No. __ (JES-l) consists of 31 pages and includes the Condensed Consolidated (Regulatory Basis) Balance Sheet for SCE&G as of December 31, 2011, and the Condensed Consolidated Income Statement (Regulatory Basis) for the twelve months ended December 31, 2011. These Statements are presented in accordance with generally accepted accounting principles, except that they exclude the accounts of South Carolina Generating Company, Inc. ("GENCO"), which otherwise would be consolidated with SCE&G in order for the financials to be in conformity with generally accepted accounting principles. These statements are consistent with similar statements previously filed with this Commission.

Q. PLEASE DESCRIBE PAGE 1 OF 4 OF EXHIBIT NO. __ (JES-2), WHICH IS ALSO PAGE 1 OF 4 OF EXHIBIT C-2 OF THE APPLICATION.

A. Page 1 of 4 of Exhibit No. __ (JES-2) is an analysis of the Company's total electric operating experience that identifies operating revenues and expenses, income for return, original cost rate base, and rate of return for the twelve months ended December 31, 2011 (the historical "Test Year").

Column 1 provides a description of the items included in determining income for return and original cost rate base.

Column 2 presents the "regulatory per books" amounts used to determine income for return and original cost rate base for the Test Year.

Column 3 summarizes the Company's accounting and pro forma adjustments that are necessary to reflect known and measurable changes to the results of the Company's electric operations for the Test Year. The detail for each pro forma adjustment by line item is listed on pages 3 and 4 of Exhibit No. __ (JES-2) and on pages 3 and 4 of Exhibit C-2 of the Application, and the totals of such adjustments are provided on page 4 of 4 of Exhibit No. __ (JES-2) and page 4 of 4 of Exhibit C-2 of the Application.

Column 4 presents the results of the Company's electric operations as adjusted for the accounting and pro forma adjustments.

Page 2 of 4 of Exhibit No. __ (JES-2) shows the retail electric results of operations after adjustments (column 2), as well as those results after application of the proposed revenue increase (columns 3 and 4).

Q. PLEASE EXPLAIN THE DERIVATION OF THE RATE OF RETURN ON ORIGINAL COST RATE BASE THAT APPEARS ON PAGE 2 OF 4 OF EXHIBIT NO. __ (JES-2), WHICH IS ALSO EXHIBIT C-2 PAGE 2 OF 4 OF THE APPLICATION.

A. On page 2 of 4 of Exhibit No. __ (JES-2), the total income for return on line 12 is divided by the total original cost rate base reflected on line 22 to derive the rate of return on original cost rate base as reflected on line 23. This exhibit shows that the Company earned only 6.64% on rate base during the Test Year, which equates to a return on common equity ("ROE") of only 7.26% compared to the authorized ROE of 10.7%. The Company would have earned 8.56% on rate base if the proposed revenue increase and the accounting and pro forma adjustments had been considered, which equates to an ROE of 10.95% as is set forth in the Company's Application.

Q. PLEASE DESCRIBE EXHIBIT NO. __ (JES-3), WHICH IS ALSO EXHIBIT C-3 OF THE APPLICATION.

A. Exhibit No. __ (JES-3) shows the computation of the proposed revenue increase and serves to reconcile the components of the increase by showing the impact of taxes and customer growth. The computation here details the 8.56% return seen on Exhibit No. __ (JES-2), page 2 of 4.

Q. PLEASE DESCRIBE EXHIBIT NO. __ (JES-4), WHICH IS ALSO EXHIBIT C-4 OF THE APPLICATION.

A. Exhibit No. __ (JES-4) is a Statement of Fixed Assets - Electric at December 31, 2011. This statement details gross Plant in Service and Construction Work in Progress ("CWIP") by FERC functional classification identified in **Column 1**.

Column 2 includes the amounts recorded on the books and records of the Company as of December 31, 2011.

Column 3 summarizes the accounting and pro forma adjustments that impact Plant in Service and CWIP as detailed in Exhibit No. __ (JES-2) pages 3 and 4 and Exhibit C-2 pages 3 and 4 of the Application.

Column 4 shows the balances after including the effects of the adjustments identified in Column 3.

Column 5 contains the amount of adjusted gross Plant in Service and CWIP allocated to retail electric operations.

Q. PLEASE DESCRIBE EXHIBIT NO. __ (JES-5), WHICH IS ALSO EXHIBIT C-5 OF THE APPLICATION.

A. Exhibit No. __ (JES-5) is the Company's Statement of Depreciation Reserves for Electric Operations at December 31, 2011. It should be noted that for purposes of presentation on this exhibit, reserves associated with intangible plant have been included with general plant reserves on line 5 of the exhibit.

Column 2 shows the amounts recorded on the Company's books for the Reserve for Depreciation by FERC functional classification as described in **Column 1**.

Column 3 summarizes the adjustments to Depreciation Reserves as detailed in Exhibit No. __ (JES-2) pages 3 and 4 and Exhibit C-2 pages 3 and 4 of the Application.

Column 4 shows the balances after including the effects of the adjustments identified in column 3.

Column 5 is the amount of Depreciation Reserves allocated to retail electric operations.

Q. PLEASE DESCRIBE EXHIBIT NO. __ (JES-6) WHICH IS ALSO EXHIBIT C-6 OF THE APPLICATION.

A. This exhibit shows the balances of fuel stock, emission allowances, materials and supplies, certain deferred debits and credits, and working capital as reflected on SCE&G's books and after the effects of the accounting and pro forma adjustments.

Q. PLEASE DESCRIBE EXHIBIT NO. __ (JES-7) WHICH IS ALSO EXHIBIT C-7 OF THE APPLICATION.

A. This exhibit shows the components of SCE&G's retail electric pro forma regulatory capitalization and the computation of its weighted average cost of capital as of December 31, 2011, the end of the Test Year, both before and after consideration of the requested increase in revenues. As shown here, the return on equity for the Test Year, after accounting and pro forma adjustments, was 7.26%. In deriving a reasonable return on rate base, the Company has used a return on equity ("ROE") of 10.95%, which is the ROE requested by the Company in the Application. An ROE of 10.95% is within the ROE range recommended by Company Witness Hevert as being fair and reasonable, although Company Witness Hevert acknowledges that 10.95% is on the conservative end of his ROE range and below his recommended ROE by 30 basis points. Company Witness Addison states that an ROE of 10.95% will allow the Company to access capital markets at reasonable rates to fund its future capital needs and, in fact, is at the lower end of the ROE range identified by Company Witness Hevert.

Q. PLEASE DESCRIBE EXHIBIT NO. __ (JES-8).

A. Exhibit No. ___ (JES-8) reflects the history of additions to and subtractions from the Storm Damage Reserve since its inception in 1996 pursuant to the authorization of this Commission in Order No. 96-15. The Storm Damage Reserve was authorized to mitigate the economic impact of catastrophic weather damages by eliminating the need to recover the expense of these damages through rates at the same time that customers are also recovering from the effects of the weather event. When originally authorized in 1996, the maximum level of the Storm Damage Reserve was set at $50 million. In 2007, recognizing that the replacement costs of the Company's transmission and distribution assets had increased over time, the Commission in Order No. 2007-680 authorized an increase in the Storm Damage Reserve to a maximum level of $100 million. However, collections for the Storm Damage Reserve were suspended indefinitely under Order No. 2010-471.

Q. WHAT IS THE CURRENT STATUS OF THE STORM DAMAGE RESERVE?

A. As shown in Exhibit No. ___ (JES-8), the balance of the Storm Damage Reserve has declined from $48,983,315 in 2007 to $30,102,980 as of July 31, 2012. Although an increase in the Storm Damage Reserve was authorized in 2007, the balance of the reserve nonetheless has continued to decline since that time as a result of several factors. There have been no collections to increase the Storm Damage Reserve since July 2010 and, thus, no offset for reductions from the reserve. The application of storm damage insurance premiums against the Storm Damage Reserve, rather than recovery of these premiums in rates as O&M expenses, has reduced the amount of the reserve by $13,531,759 since 2007. The Storm Damage Reserve has been further decreased in the amount of $17,210,377 since 2007 through the application of vegetation management expenses, as authorized by Commission Order Nos. 2009-87, 2009-845, and 2011-126.

As more fully explained by Company Witness Kissam, the application of these expenses to the Storm Damage Reserve was a very important aspect of the Company's vegetation management plan, and also has served to reduce the expected damage from a catastrophic weather event. Nonetheless, the application of these expenses against the Storm Damage Reserve further reduced the balance of that reserve. Finally, actual storm restoration charges in the amount of $4,329,212 have been applied against the Storm Damage Reserve since 2007. These charges represent the actual storm restoration costs in excess of $2.5 million in any one calendar year during that period, as was prescribed in Order No. 96-15. The combined impact of these factors has been a reduction of $18,880,353 in the Storm Damage Reserve since 2007, resulting in a balance of $30,102,980 as of July 31, 2012.

Q. WHAT ACTION IS THE COMPANY PROPOSING IN THE APPLICATION WITH RESPECT TO THE STORM DAMAGE RESERVE?

A. The Company proposes to maintain and enhance the protection afforded to the Company and its customers by reinstating collections for the Storm Damage Reserve from current rates on a going forward basis. The Company also is proposing to recover storm damage insurance premiums through base rates in future years, rather than by the continued application of those premiums to the Storm Damage Reserve. The reinstatement of collections and reduction of outflows will better allow the Storm Damage Reserve to mitigate the risk of economic loss from catastrophic weather events.

Q. PLEASE RETURN TO AND DESCRIBE EXHIBIT NO. __ (JES-2), WHICH IS ALSO EXHIBIT C-2 OF THE APPLICATION.

A. Exhibit No. __ (JES-2) details the accounting and pro forma adjustments that the Company is proposing in this proceeding, by the component of income and rate base to which each adjustment applies.

Q. PLEASE LIST THE ACCOUNTING AND PRO FORMA ADJUSTMENTS THAT YOU DISCUSS IN THIS PREFILED TESTIMONY.

A. The accounting and pro forma adjustments that I will discuss are identified below. The adjustment numbers coincide with the numbers on pages 3 and 4 of Exhibit No. __ (JES-2) and pages 3 and 4 of Exhibit C-2 of the Application. The page number directs your attention to the page in this testimony where my discussion of a particular adjustment is located.

No.	Adjustment Description	Pg.
1.	Wages, benefits & payroll taxes	14
2.	Incentive pay	15
3.	Annualize health care	15
4.	Remove employee clubs	15
5.	Property retirements	16
6.	Remove new nuclear amounts	16
7.	CWIP	16
8.	Annualize depreciation expense	17
9.	Palmetto Center Settlement	17

10.	Adjust property taxes	17
11.	Annualize insurance expense	17
12.	Environmental remediation recovery	18
13.	Edison Electric Institute membership	18
14.	Cayce business license fees	19
15.	Tax effect of annualized interest	19
16.	Remove DSM amounts	19
17.	Wateree Scrubber deferral - amortization	20
18.	Wateree Scrubber - current expense	20
19.	Wateree Scrubber - rate base adjustment	20
20.	Pension deferral – amortization	21
21.	Pension – current expense	21
22.	Pension – rate base adjustment	21
23.	Amortize capacity purchases	21
24.	Capacity purchase O&M adjustment	22
25.	Amortize $25 million weather refund overage and EIZ Tax Credit	22
26.	Remove off system sales contract	23
27.	Storm Damage Reserve	23
28.	Storm damage insurance premiums	23
29.	Amortize economic development grants	24
30.	Amortize new rate case expenses	25
31.	Canadys unit 1 retirement	25
32.	Urquhart unit 3 coal equipment retirement	25
33.	Write-off recovery	26
34.	VCS outage accrual mechanism	26

In all cases, the entries reflect amounts related to total electric operations, and tax, depreciation, plant in service, working cash, and other adjustments associated with these pro forma adjustments have been made.

The pro forma adjustments all follow established rate making and accounting policies as recognized by this Commission and are necessary to create a proper calculation of SCE&G's expenses and revenues for rate making purposes. The Commission historically has permitted known and measurable changes in revenues and expenses to be made as pro forma adjustments to historical Test Year information for purposes of rate adjustment proceedings.

Following these established policies and precedents, Test Year revenues are adjusted to reflect average customer growth that occurred during the Test Year. Likewise, certain adjustments to Test Year expenses are necessary to reflect known and measurable changes from Test Year levels. Seven of the Company's pro forma adjustments (Adjustment No. 1, Wages, benefits and payroll taxes; Adjustment No. 3, Annualize health care; Adjustment No. 5, Property Retirements; Adjustment No. 7, CWIP; Adjustment No. 8, Annualize depreciation expense; Adjustment No. 10, Adjust property tax; and Adjustment No. 11, Annualize insurance expense) are necessary to adjust expenses to current or year-end levels to properly match adjusted revenues.

Q. PLEASE DESCRIBE THE ADJUSTMENTS.

A. **<u>Adjustment No. 1, Wages, benefits, and payroll taxes.</u>** It is necessary to make this pro forma adjustment to increase the Test Year wages, benefits, and payroll taxes to reflect the current level of expense as of the time the pro forma adjustment was prepared. Adjustments of this nature have been pro forma adjustments in the Company's electric rate cases for many years and have historically been approved by the Commission in past proceedings. The effect of this adjustment is to increase O&M expenses by $10,181,230 and other taxes (specifically payroll taxes) by $722,374.

<u>Adjustment No. 2, Incentive pay.</u> This pro forma adjustment reduces incentive compensation cost and related payroll taxes charged as expenses for the Test Year to fifty percent of the amounts actually accrued. Incentive pay is a necessary and essential part of the Company's overall compensation package for its employees and is recognized as such within the utility industry. This adjustment is included for consistency with the Commission's established practice as set forth in prior orders. However, SCE&G does not mean to imply by inclusion of this adjustment that it agrees with this treatment or that it may not object to the removal of any such incentive pay costs from utility expenses in future proceedings. The effect of this adjustment is to decrease O&M expenses by $6,077,781 and other taxes (payroll taxes) by $395,279.

<u>Adjustment No. 3, Annualize health care.</u> This adjustment follows past Commission practice and annualizes healthcare costs to reflect the level of cost incurred in the last quarter of the Test Year. The result is an increase in Test Year O&M expenses of $2,128,044.

<u>Adjustment No. 4, Remove employee clubs.</u> This pro forma adjustment removes from rate consideration the investment and expenses related to employee clubs (the Pine Island Club, Sand Dunes Club, and Misty Lake Club). The effect of this adjustment is to lower O&M expenses by $412,818, common plant in service by $4,793,586, depreciation reserves by $1,629,626, and depreciation expense by $143,053.

<u>Adjustment No. 5, Property retirements.</u> This pro forma adjustment reduces plant in service and accumulated depreciation to reflect the recording of asset retirements pending as of the end of the Test Year. The effect of this adjustment is to lower plant in service by $324,824 and depreciation reserves by $324,824.

<u>Adjustment No. 6, Remove new nuclear amounts from CWIP.</u> This pro forma adjustment removes from rate base the accumulated balance of $1,256,317,802 in CWIP, other taxes (gross receipts taxes) of $380,345, and incremental revenue of $83,831,800 associated with the ongoing investment in the construction of V.C. Summer Station Units 2 & 3. The adjustment is necessary because the revenue requirements associated with the Company's new nuclear investment are determined under the provisions of the Base Load Review Act, S.C. Code Ann. §§ 58-33-200, *et seq*.

<u>Adjustment No. 7, CWIP.</u> This pro forma adjustment increases plant in service and decreases CWIP to account for certain projects that were included in CWIP at the end of the Test Year but for which the "in-service" dates occurred prior to the end of the Test Year. As with the other proposed utility plant adjustments, this entry was computed in a manner consistent with practice in prior proceedings. The result is an increase in plant in service of $2,694,279.

<u>Adjustment No. 8, Annualize depreciation expense.</u> This pro forma adjustment increases depreciation expense and reserves by $3,635,810 to provide for the recognition of a full year of depreciation at the currently approved depreciation rates, after consideration of all pro forma adjustments to the plant in service balance as of December 31, 2011.

<u>Adjustment No. 9, Palmetto Center settlement.</u> This pro forma adjustment removes costs recorded during the Test Year associated with the settlement of a dispute involving the expiration in 2009 of the Company’s lease of space at the Palmetto Center in Columbia, South Carolina. This adjustment results in a decrease in O&M expenses of $686,025.

<u>Adjustment No. 10, Adjust property taxes</u>. This pro forma adjustment applies the property tax millage rates to the assessable plant in service amounts as of the end of the Test Year, including the pro forma entries impacting taxable plant in service described herein, and thereby increases taxes other than income taxes for the Test Year by $1,213,348.

<u>Adjustment No. 11, Annualize insurance expense</u>. This pro forma adjustment increases O&M expenses by $25,170 to annualize the current cost of premiums for casualty and liability insurance policies that were in effect at the end of the Test Year.

Adjustment No. 12, Environmental remediation recovery. As discussed in the direct testimony of Company Witness Kissam, the Company is proposing an environmental recovery mechanism for its electric operations that is similar to the mechanism approved by the Commission for its gas operations. The Company is required to recognize an obligation to perform environmental remediation activities associated with its electric operations as it becomes aware of environmental issues. The cost of the remediation activities can vary significantly, and there often are significant increases to expense in the periods in which the costs are recognized. As a result, absent a recovery mechanism that levelizes these costs, a mismatch between revenue and expense can occur. In order to provide a proper match between revenue and expense and provide for a reasonable recovery of these necessary utility operating expenses, the Company is proposing that it be allowed to defer the costs of the obligations associated with electric environmental remediation activities and to amortize the deferral in an amount equal to that recovered in revenue. Based on remediation obligations at this time, the Company is proposing that an annual amortization of $240,000 be established. This pro forma entry results in an increase in O&M expenses of $240,000 to establish the amortization.

Adjustment No. 13, Edison Electric Institute dues. The Edison Electric Institute ("EEI") is the leading association of investor owned electric companies. After having not been a member for several years, including the Test Year, the Company has recently rejoined the EEI. This entry increases O&M expenses to reflect the current annual dues cost of $200,000.

Adjustment No. 14, Cayce business license fees. During the Test Year, negotiations with the City of Cayce regarding its claim for certain license fees, including some amounts related to earlier years outside of the Test Year, were concluded. This entry reduces O&M expenses by $237,838 to remove the license fees attributable to 2009 and 2010 which were paid during the Test Year.

Adjustment No. 15, Tax effect of annualized interest. This pro forma entry adjusts income taxes based on changes to interest expense associated with the rate base pro forma adjustments set forth above. Pro forma reductions in Test Year interest expense of $35,107,950 result in a pro forma increase in income tax expense of $13,428,791.

Adjustment No. 16, Remove Demand Side Management ("DSM") amounts. The Company currently recovers lost margin revenue and the costs associated with its DSM programs through a rate rider authorized by Order No. 2010-472. This entry removes those elements from the Test Year's operating results. The pro forma adjustment decreases revenues by $5,660,438, increases other taxes by $25,681, and decreases O&M expenses by $252,912.

Adjustment No. 17, Wateree Scrubber deferral – amortization. This adjustment reflects a five-year amortization of costs which have been deferred under Order Nos. 2008-741 and 2010-828. In October 2010, the Company completed and placed into service a $280 million flue gas desulphurization unit and related facilities ("Scrubber") at the Wateree Generating Station. The O&M costs and depreciation expense associated with the Scrubber have not been included in rates and, instead, have been deferred pursuant to Order Nos. 2008-741 and 2010-828. The Company proposes to include the expenses attributable to the Scrubber in current rates (see Adjustment No. 18 below) and, in this entry, also proposes to amortize the costs which have thus far been deferred. This adjustment increases amortization expense by $4,918,560.

Adjustment No. 18, Wateree Scrubber – current expense. As noted above, pursuant to Order Nos. 2008-741 and 2010-828, the Company is presently deferring the depreciation expense and incremental O&M costs associated with the Wateree Scrubber. This pro forma adjustment reflects the cessation of this deferral and the recovery of these costs in current rates. This adjustment increases depreciation expense by $12,045,600 and O&M expenses by $939,209.

Adjustment No. 19, Wateree Scrubber – rate base adjustment. This adjustment increases the Company's rate base in the amount of

$12,149,000 for the deferred costs attributable to the Wateree Scrubber discussed above (Adjustment No. 17).

Adjustment No. 20, Pension deferral – amortization. Under Order Nos. 2009-81 and 2010-471, the Company has been deferring pension expense and not including the impact of this expense in current rates. The Company proposes to begin including pension expense in current rates. This adjustment reflects the amortization of the deferred amounts over the actuarially determined twelve-year remaining service period of current employees and increases O&M expenses by $4,865,564.

Adjustment No. 21, Pension – current expense. As noted above, the Company is currently deferring its pension expense and not including the impact of this expense in current rates. This adjustment reflects the impact of the Company's request to begin recovering current pension expense through rates and to cease the deferral. This pro forma adjustment increases Test Year O&M expenses by $12,525,444 and represents the actuarially determined amount of the Company's current pension costs attributable to electric operations.

Adjustment No. 22, Pension rate base adjustment. This adjustment reflects the Company's request to include deferred pension costs of $33,049,000, as discussed above, within rate base.

Adjustment No. 23, Amortize capacity purchases. Pursuant to Order No. 2008-530, the Company has deferred certain charges for capacity purchased in order to meet customer and system needs. The Company is proposing to amortize the costs associated with these purchases over three years. This adjustment increases O&M expenses by $1,229,713.

Adjustment No. 24, Capacity purchase O&M adjustment. This adjustment reduces O&M by $850,867 for capacity purchases that were expensed during the Test Year but subsequently deferred in February 2012 pursuant to Order No. 2008-530.

Adjustment No. 25, Amortize $25 million weather refund overage and Economic Impact Zone Investment Tax Credit ("EIZ Tax Credit"). Pursuant to Order No. 2010-471, the Company utilized decrement riders to provide customers with (i) the benefits of accelerated amortization of previously deferred state EIZ Tax Credits and (ii) a refund of margins arising from abnormally cold weather in the first quarter of 2010. In order to ensure that customers on all billing cycles received the benefit of the same number of decrements, the decrements necessarily resulted in a credit that was slightly higher than the actual total amount of the stated benefits to the customers. The over-credited amounts were deferred consistent with the Order. Order No. 2010-471 further contemplated that the over-credited amounts would accrue interest at the three-year U.S. Government Treasury Notes rate, plus an all-in spread of 65 basis points (0.65 percentage points) and would be recovered through a future general rate proceeding. The Company is proposing to recover the over-credited amount over a two-year period. This adjustment reflects the amortization and recovery of the over-credited amount over a two-year period and results in a decrease in revenue of $2,000,000 and a decrease in gross receipts taxes (other taxes) of $9,074.

<u>Adjustment No. 26, Remove off-system sales contract.</u> As discussed in the Application and in the direct testimony of Company Witness Byrne, the Company entered into a wholesale power sales contract beginning in 2004 in connection with the development of the Company's Jasper Generating Station. The contract expires on December 31, 2012, and this entry reduces revenue by $30,002,977 and gross receipts taxes (other taxes) by $136,124 to reflect the expiration of the contract.

<u>Adjustment No. 27, Storm Damage Reserve.</u> This pro forma adjustment increases O&M expenses by $6,054,246 to reflect the cost of the Company's proposal to reinstate collections for the Company's Storm Damage Reserve as authorized under Order No. 96-15. As I previously explained, the Company is proposing to reinstate on a going forward basis the Storm Damage Reserve collections that were suspended indefinitely under Order No. 2010-471.

<u>Adjustment No. 28, Storm damage insurance premiums.</u> This pro forma adjustment increases O&M expenses by $3,058,167 to reflect the current cost of storm damage insurance premiums related to transmission and distribution assets. As previously discussed, the Company is proposing to recover these insurance premiums through base rates in future years. Previously, the Commission approved in Order Nos. 2007-680 and 2010-471 the application of storm insurance premiums to the Storm Damage Reserve rather than the treatment of those premiums as O&M expenses. This pro forma adjustment reflects the recovery of those premiums through base rates on a going forward basis rather than application of those premiums as a reduction to the Storm Damage Reserve.

Adjustment No. 29, Amortize economic development grants. As Company Witness Byrne is testifying, the Company continues to participate in economic development efforts to recruit jobs to South Carolina, particularly in the Company's service area. Specifically, the Company has made grants associated with plant expansions in the Company's electric service territory for Michelin North America, Inc. and Bridgestone Americas Tire Operations, LLC. In addition, the Company has made a research and development grant to Clemson University associated with a grid simulator facility. These grants have been deferred as regulatory assets pursuant to Order Nos. 2011-510, 2012-37, and 2012-662. The pro forma entry reflects a proposed five-year amortization of the grant to Clemson University and the annualization of amortization which has already begun on the other grants over terms consistent with their related electric service agreements, and as specified in the related accounting orders issued by the

Commission. The effect of this adjustment is to increase O&M expense by $660,000.

<u>Adjustment No. 30, Amortize new rate case expenses.</u> This pro forma adjustment amortizes, over three years, the estimated incremental costs of preparing and presenting this proceeding. The effect of this adjustment is to increase O&M expenses by $233,333.

<u>Adjustment No. 31, Canadys Unit 1 retirement</u>. As discussed in the Application and in the direct testimony of Company Witness Byrne, SCE&G is proposing to retire Canadys Unit 1. This entry reflects the decreases in O&M expenses, depreciation expense, and property taxes resulting from the retirement, offset by the amortization of the unrecovered plant cost over 14 years. Unrecovered plant costs, as defined by the Uniform System of Accounts I discussed previously, include any additional costs incurred related to the early retirement of an asset, as well as the unrecovered net book value of the retired asset.

<u>Adjustment No. 32, Urquhart Unit 3 coal equipment retirement.</u> Also as discussed in the Application and in Company Witness Byrne's testimony, SCE&G is proposing to retire the coal-related equipment at Urquhart Unit 3 in connection with the commitment to operate that unit using natural gas as the fuel source. This entry reflects the decreases in O&M expenses and depreciation expense which will result from such retirement.

Adjustment No. 33, Write-off recovery. This entry increases O&M expenses by $534,652 to remove the recovery of a specific commercial account bad debt from the Test Year's operating results.

Adjustment No. 34, VCS outage accrual mechanism. As presented in the direct testimony of Company Witness Byrne, V.C. Summer Unit 1 is subject to recurring refueling outages on an 18-month cycle. Under established precedent in past cases, the Company has estimated costs for each outage and then recorded those costs over the course of each 18-month cycle, in isolation. This pro forma adjustment modifies the Test Year outage accrual amount to annualize the accrual based on estimates of outage costs expected for the next five outage cycles, which equates to a period of 90 months. The effect of this adjustment is to increase Test Year expenses by $1,773,613. This approach is similar to that approved in Order Nos. 2005-2 and 2010-471, in which Orders the Commission authorized the Company to levelize certain fossil fuel turbine maintenance charges by establishing an annual accrual amount and charging actual turbine maintenance costs against that accrual.

Q. MR. SWAN, DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. It does.

Exhibit C-1
Page 1 of 31

SOUTH CAROLINA ELECTRIC & GAS COMPANY

CONDENSED CONSOLIDATED (REGULATORY BASIS) BALANCE SHEET
As of December 31, 2011

CONDENSED CONSOLIDATED (REGULATORY BASIS) STATEMENT OF INCOME
For the Twelve Months Ended December 31, 2011

South Carolina Electric & Gas Company
Condensed Consolidated Balance Sheet (Regulatory Basis)
December 31, 2011
(Dollars in Millions)

	2011
Assets:	
Total Utility Plant	$9,631
Less Accumulated Deprec. and Amortization	(3,512)
Total	6,119
Construction Work in Progress	1,470
Nuclear Fuel, Net of Accumulated Amortization	171
Utility Plant, Net	7,760
Other Property and Investments:	
Nontility Property, Net of Accum Deprec	52
Trust Assets	84
Other Investments	2
Other Property and Investments	138
Current Assets:	
Cash and Special Deposits	62
Receivable - Customer and Other	413
Receivable - Affiliated Companies	9
Inventories (At Average Cost):	
Fuel	148
Materials and Supplies	114
Emission Allowances	2
Prepayments	75
Misc. Current Assets	2
Total Current Assets	825
Deferred Debits:	
Regulatory Assets	1,235
Other	331
Total Deferred Debits	1,566
Total Assets	$10,289

South Carolina Electric & Gas Company
Condensed Consolidated Balance Sheet (Regulatory Basis)
December 31, 2011
(Dollars in Millions)

	2011
Capitalization and Liabilities:	
Capitalization:	
Common Stock	$576
Other Paid in Capital	1,469
Capital Stock Expense (Debit)	(4)
Accumulated Other Comprehensive Income	(3)
Retained Earnings	1,627
Total Common Equity	3,665
Long-Term Debt, Net	2,919
Total Capitalization	6,584
Current Liabilities:	
Short-Term Borrowings	512
Accounts Payable	225
Accounts Payable - Affiliated Companies	75
Customer Deposits	41
Taxes Accrued	145
Interest Accrued	52
Dividends Declared	38
Other	69
Total Current Liabilities	1,157
Deferred Credits	
Deferred Income Taxes	1,516
Deferred Investment Tax Credits	49
Asset Retirement Obligations	427
Post Retirement Benefit Obligation	181
Regulatory Liabilities	247
Other	128
Total Deferred Credits	2,548
Total Capitalization and Liabilities	$10,289

South Carolina Electric & Gas Company
Condensed Consolidated Income Statement (Regulatory basis)
For the Teweve Months ended December 31, 2011
(Dollars in Millions)

	12 months ended December 31, 2011
Operating Revenues:	
Electric	2,432
Gas-Regulated	387
Total Operating Revenues	2,819
Operating Expenses:	
Fuel Used in Electric Generation	810
Purchased Power	204
Gas Purchased for Resale-Regulated	240
Other Operation and Maintenance	502
Depreciation and Amortization	268
Other Taxes	177
Total Operating Expenses	2,201
Operating Income	618
Other Income	
Allowance for equity funds used during construction	13
Other Revenues	5
Other Expenses	(12)
Interest charges, net of allowance for funds	(184)
Total Other Expense	(178)
Income Before Income taxes and Preferred Stock Dividends	440
Income Taxes	135
Net Income Available for Common Shareholders	306

See Notes to Condensed Consolidated (Regulatory Basis) Financial Statements

SOUTH CAROLINA ELECTRIC & GAS COMPANY
NOTES TO FINANCIAL STATEMENTS
December 31, 2011

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Principles of Consolidation

South Carolina Electric and Gas Company (SCE&G), a public utility, is a South Carolina corporation organized in 1924 and a wholly-owned subsidiary of SCANA Corporation (SCANA), a South Carolina corporation. SCE&G engages predominantly in the generation and sale of electricity to wholesale and retail customers in South Carolina and in the purchase, sale and transportation of natural gas to retail customers in South Carolina.

The accompanying Financial Statements reflect the accounts of SCE&G and South Carolina Fuel Company (Fuel Company). Intercompany balances and transactions between SCE&G and Fuel Company have been eliminated in consolidation.

SCE&G has determined that it has a controlling financial interest in Fuel Company (which is considered to be a Variable Interest Entity (VIE)), and accordingly, the accompanying condensed financial statements include the accounts of SCE&G and Fuel Company. The equity interest in Fuel Company is held solely by SCANA, SCE&G's parent. Accordingly, Fuel Company's equity and results of operations is reflected as a noncontrolling interest in SCE&G's condensed financial statements.

Fuel Company acquires, owns and provides financing for SCE&G's nuclear fuel, certain fossil fuels and emission allowances. See also Note 4.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant

Utility plant is stated substantially at original cost. The costs of additions, replacements and betterments to utility plant, including direct labor, material and indirect charges for engineering, supervision and an allowance for funds used during construction, are added to utility plant accounts. The original cost of utility property retired or otherwise disposed of is removed from utility plant accounts and generally charged to accumulated depreciation. The costs of repairs and replacements of items of property determined to be less than a unit of property or that do not increase the asset's life or functionality are charged to expense.

Allowance for funds used during construction (AFC) is a noncash item that reflects the period cost of capital devoted to plant under construction. This accounting practice results in the inclusion of, as a component of construction cost, the costs of debt and equity capital dedicated to construction investment. AFC is included in rate base investment and depreciated as a component of plant cost in establishing rates for utility services. SCE&G calculated AFC using average composite rates of 4.6% for 2011, 7.3% for 2010 and 6.2% for 2009. These rates do not exceed the maximum allowable rate as calculated under FERC Order No. 561. SCE&G capitalizes interest on nuclear fuel in process at the actual interest cost incurred.

SCE&G records provisions for depreciation and amortization using the straight-line method based on the estimated service lives of the various classes of property. The composite weighted average depreciation rates for utility plant assets were 2.92% in 2011, 2.83% in 2010 and 2.97% in 2009.

SCE&G records nuclear fuel amortization using the units-of-production method. Nuclear fuel amortization is included in "Fuel used in electric generation" and recovered through the fuel cost component of retail electric rates. Provisions for amortization of nuclear fuel include amounts necessary to satisfy obligations to the United States Department of Energy (DOE) under a contract for disposal of spent nuclear fuel.

Jointly Owned Utility Plant

SCE&G jointly owns and is the operator of V.C. Summer Nuclear Station (Summer Station) Unit 1. In addition, SCE&G will jointly own and will be the operator of the New Units being designed and constructed at the site of Summer Station. Each joint owner provides its own financing and shares the direct expenses and generation output in proportion to its ownership of a unit. SCE&G's share of the direct expenses are included in the corresponding operating expenses on its income statement.

As of December 31, 2011	Unit 1	New Units
Percent owned	66.7%	55.0%
Plant in service	$1.0 billion	-
Accumulated depreciation	$545.0 million	-
Construction work in progress	$62.2 million	$1.2 billion
As of December 31, 2010		
Percent owned	66.7%	55.0%
Plant in service	$1.0 billion	-
Accumulated depreciation	$548.8 million	-
Construction work in progress	$40.1 million	$891.2 million

SCE&G, on behalf of itself and as agent for Santee Cooper, has contracted the consortium consisting of Westinghouse and Stone and Webster, Inc., a subsidiary of The Shaw Group, Inc. (Consortium) for the design and construction of the New Units at the site of Summer Station. SCE&G's share of the estimated cash outlays (future value, excluding AFC) totals approximately $6.0 billion for plant costs and for related transmission infrastructure costs, and is projected based on historical one-year and five year escalation rates as required by the Public Service Commission of South Carolina (SCPSC).

SCE&G's latest Integrated Resource Plan filed with the SCPSC in February 2011 continues to support SCE&G's need for 55 percent of the output of the Nuclear Units 2 and 3 (New Units). As previously reported, SCE&G has been advised by Santee Cooper that it is reviewing certain aspects of its capital improvement program and long-term power supply plan, including the level of its participation in the New Units. Santee Cooper has entered into a letter of intent with Duke Energy Carolina (Duke) that may result in Duke acquiring a portion of Santee Cooper's ownership interest in the New Units. SCE&G is unable to predict whether any change in Santee Cooper's ownership interest or the addition of new joint owners will increase project costs or delay the commercial operation dates of the New Units. Any such project cost increase or delay could be material.

The parties to the Engineering, Procurement and Construction Agreement dated Mary 23, 2008 (EPC Contract) have established both informal and formal dispute resolution procedures in order to resolve issues that arise during the course of constructing a project of this magnitude. During the course of activities under the EPC Contract, issues have materialized that may impact project budget and schedule, including those related to Combined Construction and Operating License (COL) delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site. These issues have resulted in assertions of contractual entitlement to recover additional costs and may result in requests for change orders by members of the Consortium. While SCE&G has not accepted the validity of any claims, the amount of the claims (SCE&G's portion) could be as much as $188 million. SCE&G expects to resolve any such disputes through both the informal and formal procedures and anticipates that any additional costs that arise through such dispute resolution processes, as well as other costs identified from time to time (see Note 2 to the financial statements), will be recoverable through rates.

Included within receivables on the balance sheet were amounts due to SCE&G from Santee Cooper for its share of direct expenses and construction costs for Summer Station Unit 1 and the New Units. These amounts totaled $63.6 million at December 31, 2011 and $77.9 million at December 31, 2010.

Major Maintenance

Planned major maintenance costs related to certain fossil fuel turbine equipment and nuclear refueling outages are accrued in periods other than when incurred in accordance with approval by the SCPSC for such accounting treatment and rate recovery of expenses accrued thereunder. Other planned major maintenance is expensed when incurred. Through 2017, SCE&G is authorized to collect $18.4 million annually through electric rates to offset certain turbine maintenance expenditures. For the year ended December 31, 2011, SCE&G incurred $11.5 million for turbine maintenance. Cumulative costs for turbine maintenance in excess of cumulative collections are classified as a regulatory asset on the balance sheet. Nuclear refueling outages are scheduled 18 months apart, and SCE&G begins accruing for each successive scheduled outage upon completion of the preceding scheduled outage. SCE&G accrued $1.2 million per month from July 2008 through July 2011 for its portion of the outages in the fall of 2009 and the spring of 2011. Total costs for the 2009 outage were $32.7 million, of which SCE&G was responsible for $21.8 million. Total costs for the 2011 outage were $34.1 million, of which SCE&G was responsible for $22.7 million. In July 2011, SCE&G began accruing $1.2 million per month for its portion of the refueling planned for the fall of 2012. SCE&G had an accrued balance of $7.2 million at December 31, 2011 and $14.3 million at December 31, 2010.

Nuclear Decommissioning

SCE&G’s two-thirds share of estimated site-specific nuclear decommissioning costs for Summer Station Unit 1, including the cost of decommissioning plant components both subject to and not subject to radioactive contamination, totals $451.0 million, stated in 2006 dollars. Santee Cooper is responsible for decommissioning costs related to its one-third ownership interest in Summer Station Unit 1. The cost estimate assumes that the site would be maintained over a period of approximately 60 years in such a manner as to allow for subsequent decontamination that would permit release for unrestricted use.

Under SCE&G’s method of funding decommissioning costs, amounts collected through rates ($3.2 million pre-tax in each of 2011, 2010 and 2009) are invested in insurance policies on the lives of certain SCE&G and affiliate personnel. SCE&G transfers to an external trust fund the amounts collected through electric rates, insurance proceeds and interest thereon, less expenses. The trusteed asset balance reflects the net cash surrender value of the insurance policies and cash held by the trust. Management intends for the fund, including earnings thereon, to provide for all eventual decommissioning expenditures for Summer Station Unit 1 on an after-tax basis.

Cash and Cash Equivalents

SCE&G considers temporary cash investments having original maturities of three months or less at time of purchase to be cash equivalents. These cash equivalents are generally in the form of commercial paper, certificates of deposit, repurchase agreements, treasury bills and notes.

Account Receivable

Accounts receivable reflect amounts due from customers arising from the delivery of energy or related services and include revenues earned pursuant to revenue recognition practices described below. These receivables include both billed and unbilled amounts. Receivables are generally due within one month of receipt of invoices which are presented on a monthly cycle basis.

Income Taxes

SCE&G is included in the federal income tax return of SCANA. Under a joint income tax allocation agreement, each SCANA subsidiary’s current and deferred tax expense is computed on a stand-alone basis. Deferred tax assets and liabilities are recorded for the tax effects of all significant temporary differences between the book basis and tax basis of assets and liabilities at currently enacted tax rates. Deferred tax assets and liabilities are adjusted for changes in such tax rates through charges or credits to regulatory assets or liabilities if they are expected to be recovered from, or passed through to, customers; otherwise, they are charged or credited to income tax expense. Also under provisions of the income tax allocation agreement, certain tax benefits of the parent holding company are distributed in cash to taxpaying affiliates, including SCE&G, in the form of capital contributions.

Regulatory Assets and Regulatory Liabilities

SCE&G records costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by a nonregulated enterprise. These regulatory assets and liabilities represent expenses deferred for future recovery from customers or obligations to be refunded to customers and are primarily classified in the balance sheet as regulatory assets and regulatory liabilities (See Note 2). The regulatory assets and liabilities are amortized consistent with the treatment of the related costs in the ratemaking process.

Debt Premium, Discount and Expense, Unamortized Loss on Reacquired Debt

SCE&G records long-term debt premium and discount within long-term debt and amortizes them as components of interest charges over the terms of the respective debt issues. Other issuance expense and gains or losses on reacquired debt that is refinanced are recorded in other deferred debits or credits and are amortized over the term of the replacement debt, also as interest charges.

Environmental

SCE&G maintains an environmental assessment program to identify and evaluate current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. Environmental remediation liabilities are accrued when the criteria for loss contingencies are met. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Probable and estimable costs are accrued related to environmental sites on an undiscounted basis. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. Amounts expected to be recovered through rates are recorded in deferred debits and, if applicable, amortized over approved amortization periods. Other environmental costs are recorded to expense.

Income Statement Presentation

In its statements of income, SCE&G presents the activities of its regulated businesses (including those activities of segments described in Note 12) within operating income, and it presents all other activities within other income (expense).

Revenue Recognition

SCE&G records revenues during the accounting period in which it provides services to customers and includes estimated amounts for electricity and natural gas delivered but not yet billed. Unbilled revenues totaled $117.8 million at December 31, 2011 and $123.4 million at December 31, 2010.

Fuel costs, emission allowances and certain environmental reagent costs for electric generation are collected through the fuel cost component in retail electric rates. This component is established by the SCPSC during annual fuel cost hearings. Any difference between actual fuel costs and amounts contained in the fuel cost component is deferred and included when determining the fuel cost component during the next annual hearing.

Customers subject to the Purchased Gas Adjustment (PGA) are billed based on a cost of gas factor calculated in accordance with a gas cost recovery procedure approved by the SCPSC and subject to adjustment monthly. Any difference between actual gas costs and amounts contained in rates is deferred and included when making the next adjustment to the cost of gas factor. In addition, included in these deferred amounts are realized gains and losses incurred in SCE&G's natural gas hedging program.

SCE&G's gas rate schedules for residential, small commercial and small industrial customers include a weather normalization adjustment (WNA) which minimizes fluctuations in gas revenues due to abnormal weather conditions. In August 2010, SCE&G implemented a pilot electric WNA (eWNA) on a one-year pilot basis for its electric customers, and it will continue on a pilot basis unless modified or terminated by the SCPSC.

Taxes that are billed to and collected from customers are recorded as liabilities until they are remitted to the respective taxing authority. Accordingly, no such taxes are included in revenues or expenses in the statements of income.

New Accounting Matter

Effective for the first quarter of 2012, SCE&G will adopt accounting guidance that revises how comprehensive income is presented in its financial statements. SCE&G does not expect the adoption of this guidance to impact results of operations, cash flows or financial position.

2. RATE AND OTHER REGULATORY MATTERS

SCE&G

Electric

SCE&G's retail electric rates are established in part by using a cost of fuel component approved by the SCPSC which may be adjusted periodically to reflect changes in the price of fuel purchased by SCE&G. Effective with the first billing cycle of May 2010, the SCPSC approved a settlement agreement authorizing SCE&G to decrease the fuel cost portion of its electric rates. The settlement agreement incorporated SCE&G's proposal to accelerate the recognition of $17.4 million of previously deferred state income tax credits and record an offsetting reduction to the recovery of fuel costs. In addition, SCE&G agreed to defer recovery of its actual undercollected base fuel costs as of April 30, 2010 until May 2011. SCE&G was allowed to charge and accrue carrying costs monthly on the actual base fuel costs undercollected balance as of the end of each month during this deferral period. In February 2011, SCE&G requested authorization to increase the cost of fuel component of its retail electric rates to be effective with the first billing cycle of May 2011. On March 17, 2011, SCE&G, the South Carolina Office of Regulatory Staff (ORS) and the South Carolina Energy Users Committee (SCEUC) entered into a settlement agreement in which SCE&G agreed to recover its actual base fuel under-collected balance as of April 30, 2011 over a two-year period commencing with the first billing cycle of May 2011. The settlement agreement also provided that SCE&G would be allowed to charge and accrue carrying costs monthly on the deferred balance. By order dated April 26, 2011, the SCPSC approved the settlement agreement. In February 2012, SCE&G requested authorization to decrease the cost of fuel component of its retail electric rates effective with the first billing cycle of May 2012. The next annual hearing to review base rates for fuel costs is scheduled for March 22, 2012.

On July 15, 2010, the SCPSC issued an order approving a 4.88% overall increase in SCE&G's retail electric base rates and authorized an allowed return on common equity of 10.7%. Among other things, the SCPSC's order (1) included implementation of an eWNA for SCE&G's electric customers, which began in August 2010, (2) provided for a $25 million credit, over one year, to SCE&G's customers to be offset by amortization of weather-related revenues which were deferred in the first quarter of 2010 pursuant to a stipulation between SCE&G and the ORS, (3) provided for a $48.7 million credit to SCE&G's customers over two years to be offset by accelerated recognition of previously deferred state income tax credits and (4) provided for the recovery of certain federally-mandated capital expenditures that had been included in utility plant but were not being depreciated.

On July 15, 2010, the SCPSC issued an order approving the implementation by SCE&G of certain demand side management programs (DSM Programs), including the establishment of an annual rider to allow recovery of the costs and lost net margin revenue associated with DSM Programs, along with an incentive for investing in such programs. The SCPSC's order approved various settlement agreements among SCE&G, the ORS and other intervening parties. On July 27, 2010, SCE&G filed the rate rider tariff sheet for DSM Programs with the SCPSC.

The tariff rider was applied to bills rendered on or after October 30, 2010. The order requires that SCE&G submit annual filings to the SCPSC regarding the DSM Programs, net lost revenues, program costs, incentives and net program benefits. In January 2011, SCE&G submitted to the SCPSC its annual update on DSM Programs. Included in the filing was a petition to update the rate rider to provide for the recovery of costs, lost net margin revenue, and the approved shared savings incentive for investing in such DSM Programs. By order dated May 24, 2011, the SCPSC approved the updated rate rider and authorized SCE&G to increase its rates for DSM Programs as set forth in its petition. The increase became effective the first billing cycle of June 2011. In January 2012, SCE&G submitted to the SCPSC its annual update on DSM programs. Included in the filing was a petition to update the rate rider to provide for the recovery of costs, lost net revenue, and the approved shared savings incentive for investing in such DSM Programs.

Electric – Base Load Review Act (BLRA)

In January 2010, the SCPSC approved SCE&G's request for an order pursuant to the BLRA to approve an updated construction and capital cost schedule for the construction of two new nuclear generating units at Summer Station. The updated schedule provides details of the construction and capital cost schedule beyond what was proposed and included in the original BLRA filing described below.

In February 2009, the SCPSC approved SCE&G's combined application pursuant to the BLRA seeking a certificate of environmental compatibility and public convenience and necessity and for a base load review order relating to the proposed construction and operation by SCE&G and Santee Cooper of the New Units at Summer Station. Under the BLRA, the SCPSC conducted a full pre-construction prudency review of the proposed units and the engineering, procurement, and construction contract under which they are being built. The SCPSC prudency finding is binding on all future related rate proceedings so long as the construction proceeds in accordance with schedules, estimates and projections, as approved by the SCPSC.

In May 2009, two intervenors filed separate appeals of the SCPSC order with the South Carolina Supreme Court. With regard to the first appeal, which challenged the SCPSC's prudency finding, the South Carolina Supreme Court issued an opinion on April 26, 2010, affirming the decision of the SCPSC. As for the second appeal, the South Carolina Supreme Court reversed the SCPSC's decision to allow SCE&G to include a pre-approved cost contingency fund and associated inflation (contingency reserve) as part of its anticipated capital costs allowed under the BLRA. SCE&G's share of the project, as originally approved by the SCPSC, was $4.5 billion in 2007 dollars. Approximately $438 million represented contingency costs associated with the project. Without the pre-approved contingency reserve, SCE&G must seek SCPSC approval for the recovery of any additional capital costs. The Court's ruling, however, did not affect the project schedule or disturb the SCPSC's issuance of a certificate of environmental compatibility and public convenience and necessity, which is required to construct the New Units. On November 15, 2010, SCE&G filed a petition with the SCPSC seeking an order approving an updated capital cost schedule that reflected the removal of the contingency reserve and incorporated then identifiable capital costs of $173.9 million, and by order dated May 16, 2011, the SCPSC approved the updated capital costs schedule as outlined in the petition.

On February 29, 2012, SCE&G filed a petition with the SCPSC seeking an order approving a further updated capital cost and construction schedule that incorporates additional identifiable capital costs of approximately $6 million (SCE&G's portion) related to new federal healthcare laws, information security measures and certain minor design modifications. That petition also includes increased capital costs of approximately $12 million (SCE&G's portion) related to transmission infrastructure. Finally, that petition includes amounts of approximately $150 million (SCE&G's portion) related to additional skills, training and experience for the staff which will operate the New Units, the accelerated hiring and training of staff to meet an accelerated completion and in-service date of the second New Unit, and facilities, equipment and information technology systems required to support the New Units and their personnel. Future petitions would be filed for any costs arising from the resolution of the commercial claims discussed in Note 1 to the financial statements (e.g., those related to COL delays, design modifications of the shield building and certain pre-fabricated modules for the New Units and unanticipated rock conditions at the site).

Under the BLRA, SCE&G is allowed to file revised rates with the SCPSC each year to incorporate the financing cost of any incremental construction work in progress incurred for new nuclear generation. Requested rate adjustments are based on SCE&G's updated cost of debt and capital structure and on an allowed return on common equity of 11%. The SCPSC has approved the following rate requests under the BLRA effective for bills rendered on and after October 30 in the following years:

Year	Increase	Amount
2011	2.4%	$ 52.8 million
2010	2.3%	$ 47.3 million
2009	1.1%	$ 22.5 million

Gas

SCE&G

The Natural Gas Rate Stabilization Act (RSA) is designed to reduce the volatility of costs charged to customers by allowing for more timely recovery of the costs that regulated utilities incur related to natural gas infrastructure. The SCPSC has approved the following rate changes pursuant to annual RSA filings effective with the billing cycle of November in the following years:

Year	Action		Amount
2011	2.1%	Increase	$ 8.6 million
2010	2.1%	Decrease	$ 10.4 million
2009	2.5%	Increase	$ 13.0 million

SCE&G's natural gas tariffs include a PGA clause that provides for the recovery of actual gas costs incurred, including costs related to hedging natural gas purchasing activities. SCE&G's gas rates are calculated using a methodology which may adjust the cost of gas monthly based on a 12-month rolling average. The annual Purchased Gas Adjustment (PGA) hearing to review SCE&G's gas purchasing policies and procedures was conducted in November 2011 before the SCPSC. The SCPSC issued an order in January 2012 finding that SCE&G's gas purchasing policies and practices during the review period of August 1, 2010 through July 31, 2011, were reasonable and prudent and authorized the suspension of SCE&G's natural gas hedging program.

Regulatory Assets and Regulatory Liabilities

SCE&G's cost-based, rate-regulated utilities recognize in their financial statements certain revenues and expenses in different time periods than do enterprises that are not rate-regulated. As a result, SCE&G has recorded regulatory assets and liabilities which are summarized in the following tables. Substantially all of its regulatory assets are either explicitly excluded from rate base or are effectively excluded from rate base due to their being offset by related liabilities.

	December 31,	
Millions of dollars	**2011**	**2010**
Regulatory Assets:		
Accumulated deferred income taxes	$221	$191
Under-collections-electric fuel adjustment clause	28	25
Environmental remediation costs	25	26
AROs and related funding	279	267
Franchise agreements	40	45
Deferred employee benefit plan costs	347	288
Planned major maintenance	6	6
Deferred losses on interest rate derivatives	146	82
Deferred pollution control costs	25	13
Other	41	20
Total Regulatory Assets	$1,158	$963
Regulatory Liabilities:		
Accumulated deferred income taxes	$21	$24

Asset removal costs	460	532
Storm damage reserve	32	38
Deferred gains on interest rate derivatives	24	26
Other	3	4
Total Regulatory Liabilities	$540	$624

Accumulated deferred income tax liabilities arising from utility operations that have not been included in customer rates are recorded as a regulatory asset. Substantially all of these regulatory assets are expected to be recovered over the remaining lives of the related property which may range up to approximately 70 years. Similarly, accumulated deferred income tax assets arising from deferred investment tax credits are recorded as a regulatory liability.

Under-collections-electric fuel adjustment clause represents amounts due from customers pursuant to the fuel adjustment clause as approved by the SCPSC during annual hearings which are expected to be recovered in retail electric rates in future periods. These amounts are expected to be recovered in retail electric rates during the period January 2013 through April 2013. SCE&G is allowed to recover interest on actual base fuel deferred balances through the recovery period.

Environmental remediation costs represent costs associated with the assessment and clean-up of manufactured gas plant (MGP) sites currently or formerly owned by SCE&G. These regulatory assets are expected to be recovered over periods of up to approximately 23 years.

ARO and related funding represents the regulatory asset associated with the legal obligation to decommission and dismantle Summer Station Unit 1 and conditional AROs. These regulatory assets are expected to be recovered over the related property lives and periods of decommissioning which may range up to approximately 95 years.

Franchise agreements represent costs associated with electric and gas franchise agreements with the cities of Charleston and Columbia, South Carolina. Based on an SCPSC order, SCE&G began amortizing these amounts through cost of service rates in February 2003 over approximately 20 years.

Employee benefit plan costs of the regulated utilities have historically been recovered as they have been recorded under generally accepted accounting principles. Deferred employee benefit plan costs represent amounts of pension and other postretirement benefit costs which were accrued as liabilities and treated as regulatory assets pursuant to the United States Federal Energy Regulatory Commission (FERC) guidance, and costs deferred pursuant to specific SCPSC regulatory orders. A significant majority of these deferred costs are expected to be recovered through utility rates over average service periods of participating employees, or up to approximately 14 years, although recovery periods could become larger at the election of the SCPSC.

Planned major maintenance related to certain fossil fuel turbine/generation equipment and nuclear refueling outages is accrued in periods other than when incurred, as approved pursuant to specific SCPSC orders. SCE&G collected $8.5 million annually through July 15, 2010, through electric rates, to offset certain turbine maintenance expenditures. After July 15, 2010, SCE&G began collecting $18.4 million annually for this purpose. Nuclear refueling charges are accrued during each 18-month refueling outage cycle as a component of cost of service.

Deferred losses or gains on interest rate derivatives represent the effective portions of changes in fair value and payments made or received upon termination of certain interest rate swaps designated as cash flow hedges. These amounts are expected to be amortized to interest expense over the lives of the underlying debt, up to approximately 30 years.

Deferred pollution control costs represent deferred depreciation and operating and maintenance costs associated with the installation of scrubbers at Wateree and Williams Stations pursuant to specific regulatory orders. Such costs related to Williams Station amount to $9.4 million at December 31, 2011 and are being recovered through utility rates over approximately 30 years. The remaining costs relate to Wateree Station, for which SCE&G will seek recovery in future proceedings before the SCPSC. SCE&G is allowed to accrue interest on deferred costs

Exhibit C-1
Page 13 of 31

related to Wateree Station.

Various other regulatory assets are expected to be recovered in rates over periods of up to approximately 30 years.

Asset removal costs represent estimated net collections through depreciation rates of amounts to be incurred for the removal of assets in the future.

The storm damage reserve represents an SCPSC-approved collection through SCE&G electric rates, capped at $100 million, which can be applied to offset incremental storm damage costs in excess of $2.5 million in a calendar year, certain transmission and distribution insurance premiums and certain tree trimming and vegetation management expenditures in excess of amounts included in base rates. During the years ended December 31, 2011 and 2010, SCE&G applied costs of $6.4 million and $9.5 million, respectively, to the reserve. Pursuant to SCPSC's July 2010 retail electric rate order approving an electric rate increase, SCE&G suspended collection of the storm damage reserve indefinitely pending future SCPSC action.

The SCPSC or the FERC have reviewed and approved through specific orders most of the items shown as regulatory assets. Other regulatory assets include, but are not limited to, certain costs which have not been approved for recovery by the SCPSC or by FERC. In recording these costs as regulatory assets, management believes the costs will be allowable under existing rate-making concepts that are embodied in rate orders received by SCE&G. The costs are currently not being recovered, but are expected to be recovered through rates in future periods. In the future, as a result of deregulation or other changes in the regulatory environment or changes in accounting requirements, SCE&G could be required to write off its regulatory assets and liabilities. Such an event could have a material effect on SCE&G's results of operations, liquidity or financial position in the period the write-off would be recorded.

3. EQUITY

Authorized shares of SCE&G common stock were 50 million as of December 31, 2011 and 2010. Authorized shares of SCE&G preferred stock were 20 million, none of which were issued or outstanding, as of December 31, 2011 and 2010.

SCE&G's articles of incorporation do not limit the dividends that may be paid on its common stock. However, SCE&G's bond indenture contains provisions that, under certain circumstances, which SCE&G considers to be remote, could limit the payment of cash dividends on its common stock.

With respect to hydroelectric projects, the Federal Power Act requires the appropriation of a portion of certain earnings therefrom. At December 31, 2011, $58.8 million of retained earnings were restricted by this requirement as to payment of cash dividends on common stock.

4. LONG-TERM AND SHORT-TERM DEBT

Long-term debt by type with related weighted average interest rates and maturities at December 31 is as follows:

Dollars in millions	Maturity	2011 Balance	2011 Rate	2010 Balance	2010 Rate
First Mortgage Bonds (secured)	2013 - 2041	$2,790	5.89%	$2,560	6.03%
Industrial and Pollution Control Bonds[(a)]	2012 - 2038	125	4.58%	155	4.80%
Other	2012 - 2027	22		24	
Total debt		2,937		2,739	
Current maturities of long-term debt		(13)		(7)	
Unamortized discount		(11)		(14)	
Total long-term debt, net		$2,913		$2,718	

(a) Includes variable rate debt hedged by fixed rate swaps of $71.4 million in 2011 and 2010.

The annual amounts of long-term debt maturities for the years 2012 through 2016 are summarized as follows:

Year	Millions of dollars
2012	$13
2013	157
2014	4
2015	1
2016	1

In January 2012, SCE&G issued $250 million of 4.35% first mortgage bonds due February 1, 2042. Proceeds from the sale were used to repay short-term debt primarily incurred as a result of our construction program, to finance capital expenditures and for general corporate purposes.

Substantially all of SCE&G's electric utility plant is pledged as collateral in connection with long-term debt. SCE&G is in compliance with all debt covenants.

Lines of Credit and Short-Term Borrowings

At December 31, 2011 and 2010, SCE&G (including Fuel Company) had available the following committed lines of credit (LOC) and had outstanding the following LOC advances, commercial paper, and LOC-supported letter of credit obligations:

Millions of dollars	2011	2010
Lines of credit:		
Committed long-term		
Total	$1,100	$1,100
LOC advances	-	-
Weighted average interest rate	-	-
Outstanding commercial paper (270 or fewer days)	$512	$381
Weighted average interest rate	.56%	.42%
Letters of credit supported by an LOC	$.3	$.3
Available	$588	$719

SCE&G and Fuel Company are parties to five-year credit agreements in the amount of $1.1 billion (of which $400 million relates to Fuel Company), which expire October 23, 2015. These credit agreements are used for general corporate purposes, including liquidity support for each company's commercial paper program and working capital needs and, in the case of Fuel Company, to finance or refinance the purchase of nuclear fuel, certain fossil fuels, and emission and other environmental allowances. These committed long-term facilities are revolving lines of credit under credit agreements with a syndicate of banks. Wells Fargo Bank, National Association, Bank of America, N. A. and Morgan Stanley Bank, N.A. each provide 10% of the aggregate $1.1 billion credit facilities, Branch Banking and Trust Company, Credit Suisse AG, Cayman Islands Branch, JPMorgan Chase Bank, N.A., Mizuho Corporate Bank, Ltd., TD Bank N.A. and UBS Loan Finance LLC each provide 8%, and Deutsche Bank AG New York Branch, Union Bank, N.A. and U.S. Bank National Association each provide 5.3%. Three other banks provide the remaining 6%. These bank credit facilities support the issuance of commercial paper by SCE&G (including Fuel Company). When the commercial paper markets are dislocated (due to either price or availability constraints), the credit facilities are available to support the borrowing needs of SCE&G (including Fuel Company).

SCE&G is obligated with respect to an aggregate $68.3 million of industrial revenue bonds which are secured by letters of credit issued by Branch Banking and Trust Company. These letters of credit expire, subject to renewal, in the fourth quarter of 2014. SCE&G pays fees to banks as compensation for maintaining committed lines of credit.

5. INCOME TAXES

Total income tax expense attributable to income for 2011, 2010 and 2009 is as follows:

Millions of dollars	2011	2010	2009
Current taxes:			
Federal	$53	$(49)	$60
State	10	(1)	(7)
Total current taxes	63	(50)	53
Deferred taxes, net:			
Federal	92	194	73
State	7	17	6
Total deferred taxes	99	211	79
Investment tax credits:			
Deferred-state	-	-	20
Amortization of amounts deferred—state	(25)	(28)	(9)
Amortization of amounts deferred—federal	(2)	(2)	(2)
Total investment tax credits	(27)	(30)	9
Total income tax expense	$135	$131	$141

The difference between actual income tax expense and the amount calculated from the application of the statutory 35% federal income tax rate to pre-tax income is reconciled as follows:

Millions of dollars	2011	2010	2009
Net income	$306	$290	$281
Income tax expense	135	131	141
Total pre-tax income	$441	$421	$422
Income taxes on above at statutory federal income tax rate	$155	$147	$148
Increases (decreases) attributed to:			
Allowance for equity funds used during construction	(5)	(8)	(8)
State income taxes (less federal income tax effect)	11	10	7
State investment tax credits (less federal income tax effect)	(16)	(18)	-
Amortization of federal investment tax credits	(2)	(2)	(2)
Domestic production activities deduction	(6)	-	(4)
Other differences, net	(2)	2	-
Total income tax expense	$135	$131	$141

The tax effects of significant temporary differences comprising SCE&G's net deferred tax liability of $1.3 billion at December 31, 2011 and $1.2 billion at December 31, 2010 are as follows:

Millions of dollars	2011	2010
Deferred tax assets:		
Nondeductible reserves	$81	$85
Nuclear decommissioning	47	45
Unamortized investment tax credits	27	38
Deferred compensation	7	8
Unbilled revenue	19	19
Other	7	2
Total deferred tax assets	188	197
Deferred tax liabilities:		
Property, plant and equipment	1,249	1,138
Pension plan income	28	45
Deferred employee benefit plan costs	109	91
Deferred fuel costs	48	42
Other	47	43
Total deferred tax liabilities	1,481	1,359
Net deferred tax liability	$1,293	$1,162

SCE&G is included in the federal income tax return of SCANA and files various applicable state and local income tax returns. The Internal Revenue Service (IRS) has completed examinations of SCANA's federal returns through 2004, and SCANA's federal returns through 2007 are closed for additional assessment. With few exceptions, SCE&G is no longer subject to state and local income tax examinations by tax authorities for years before 2008.

In the first quarter of 2010, in connection with a fuel cost recovery settlement (see Note 2), SCE&G accelerated the recognition of certain previously deferred state income tax credits. In the second quarter of 2010, SCE&G revised (reduced) its estimate of the benefit to be realized from the domestic production activities deduction as a result of a change in method of accounting for certain repairs for tax purposes. In the third quarter of 2010, in connection with the adoption of new retail electric base rates, and pursuant to an SCPSC order, SCE&G accelerated the recognition of additional previously deferred state income tax credits (see Note 2) and also adopted the flow through method of accounting for current and future state tax credits.

Changes to Unrecognized Tax Benefits

Millions of dollars	2011	2010
Unrecognized tax benefits, January 1	$33	-
Gross increases-tax positions in prior period	5	-
Gross decreases-tax positions in prior period	(8)	-
Gross increases-current period tax positions	5	$33
Settlements	-	-
Lapse of statute of limitations	-	-
Unrecognized tax benefits, December 31	$35	$33

In connection with the change in method of accounting for certain repair costs for tax purposes referred to above, SCE&G identified approximately $35 million of unrecognized tax benefit. Because this method change is primarily a temporary difference, this additional benefit, if recognized, would not have a significant effect on the effective tax rate. By December 31, 2012, it is reasonably possible that this unrecognized tax benefit could increase by as much as $12 million or decrease by as much as $35 million. The events that could cause these changes are direct settlements with taxing authorities, legal or administrative guidance by relevant taxing authorities, or the lapse of an applicable statute of limitation.

SCE&G recognizes interest accrued related to unrecognized tax benefits within interest expense and recognizes tax penalties within other expenses. SCE&G has not accrued any significant amount of interest expense related to unrecognized tax benefits or tax penalties in 2010 or 2009. SCE&G has accrued $1.4 million of interest expense related to unrecognized tax benefits in 2011.

6. DERIVATIVE FINANCIAL INSTRUMENTS

SCE&G recognizes all derivative instruments as either assets or liabilities in the statement of financial position and measures those instruments at fair value. SCE&G recognizes changes in the fair value of derivative instruments either in earnings or within regulatory assets or regulatory liabilities, depending upon the intended use of the derivative and the resulting designation. The fair value of derivative instruments is determined by reference to quoted market prices of listed contracts, published quotations or, for interest rate swaps, discounted cash flow models with independently sourced data.

Policies and procedures and risk limits are established to control the level of market, credit, liquidity and operational and administrative risks assumed by SCE&G. SCANA's Board of Directors has delegated to a Risk Management Committee the authority to set risk limits, establish policies and procedures for risk management and measurement, and oversee and review the risk management process and infrastructure for SCANA and each of its subsidiaries, including SCE&G. The Risk Management Committee, which is comprised of certain officers, including the SCE&G's Risk Management Officer and senior officers, apprises the Board of Directors with regard to the management of risk and brings to the Board's attention any areas of concern. Written policies define the physical and financial transactions that are approved, as well as the authorization requirements and limits for transactions.

Commodity Derivatives

SCE&G uses derivative instruments to hedge forward purchases and sales of natural gas, which create market risks of different types. Instruments designated as cash flow hedges are used to hedge risks associated with fixed price obligations in a volatile market and risks associated with price differentials at different delivery locations. The basic types of financial instruments utilized are exchange-traded instruments, such as New York Mercantile Exchange (NYMEX) futures contracts or options, and over-the-counter instruments such as options and swaps, which are typically offered by energy and financial institutions. Cash settlement of commodity derivatives are classified as an operating activity in the statements of cash flows.

SCE&G's tariffs include a PGA that provides for the recovery of actual gas costs incurred. The SCPSC has ruled that the results of these hedging activities are to be included in the PGA. As such, the cost of derivatives and gains and losses on such derivatives utilized to hedge gas purchasing activities are recoverable through the weighted average cost of gas calculation. The offset to the change in fair value of these derivatives is recorded as a regulatory asset or liability. These derivative financial instruments are not designated as hedges for accounting purposes.

Interest Rate Swaps

SCE&G synthetically converts variable rate debt to fixed rate debt using swaps that are designated as cash flow hedges. Periodic payments to or receipts from swap counterparties related to these derivatives are recorded within interest expense and are classified as an operating activity for cash flow purposes.

In anticipation of the issuance of debt, SCE&G may use treasury rate lock or forward starting swap agreements that are designated as cash flow hedges. The effective portions of changes in fair value and payments made or received upon termination of such agreements are recorded in regulatory assets or regulatory liabilities. Such amounts are amortized to interest expense over the term of the underlying debt. Ineffective portions are recognized in income. Cash payments made or received upon termination of these financial instruments are classified as an investing activity in the statements of cash flows.

The effective portion of settlement payments made or received upon termination are amortized to interest expense over the term of the underlying debt and are classified as a financing activity in the statements of cash flows.

Quantitative Disclosures Related to Derivatives

SCE&G was party to natural gas derivative contracts for 2,490,000 dekatherms (DT) and 2,460,000 DT at December 31, 2011 and 2010, respectively. SCE&G was a party to interest rate swaps designated as cash flow hedges with aggregate notional amounts of $435.0 million and $385.0 million at December 31, 2011 and 2010, respectively.

The fair value of energy-related derivatives and interest rate derivatives was reflected in the balance sheet as follows:

	Fair Values of Derivative Instruments			
	Asset Derivatives		**Liability Derivatives**	
Millions of dollars	**Balance Sheet Location(a)**	**Fair Value**	**Balance Sheet Location(a)**	**Fair Value**
As of December 31, 2011				
Derivatives designated as hedging instruments				
Interest rate contracts	Other current assets	$1	Other current liabilities	$1
			Other deferred credits	67
Total		$1		$68
As of December 31, 2010				
Derivatives designated as hedging instruments				
Interest rate contracts	Other deferred debits	$4	Other current liabilities	$34
			Other deferred credits	-
Total		$4		$34
Derivatives not designated as hedging instruments				
Commodity contracts	Prepayments and other	$1		

(a) Asset derivatives represent unrealized gains to SCE&G, and liability derivatives represent unrealized losses. In SCE&G's balance sheet, unrealized gain and loss positions on commodity contracts with the same counterparty are reported as either a net asset or liability, and for purposes of the above disclosure they are reported on a gross basis.

The effect of derivative instruments on the statement of income is as follows:

Derivatives in Cash Flow Hedging Relationships Millions of dollars	**Gain or (Loss) Deferred in Regulatory Accounts (Effective Portion)**	**Gain or (Loss) Reclassified from Deferred Accounts into Income (Effective Portion)** Location	Amount
Year Ended December 31, 2011			
Interest rate contracts	$(68)	Interest expense	$(2)
Year Ended December 31, 2010			
Interest rate contracts	$(35)	Interest expense	$(1)
Year Ended December 31, 2009			
Interest rate contracts	$39	Interest expense	$(1)

Derivatives Not Designated as Hedging Instruments Millions of dollars	**Gain or (Loss) Recognized in Income** Location	Amount
Year Ended December 31, 2011		
Commodity contracts	Gas purchased for resale	$(2)
Year Ended December 31, 2010		
Commodity contracts	Gas purchased for resale	$(3)
Year Ended December 31, 2009		
Commodity contracts	Gas purchased for resale	$(16)

Exhibit C-1
Page 19 of 31

Hedge Ineffectiveness

Other gains (losses) recognized in income representing interest rate hedge ineffectiveness were $(0.6) million, net of tax, in 2011 and were insignificant in 2010. These amounts are recorded within interest expense on the statement of income

Credit Risk Considerations

Certain of SCE&G's derivative instruments contain contingent provisions that require collateral to be provided upon the occurrence of specific events, primarily credit downgrades. As of December 31, 2011 and 2010, SCE&G has posted $45.0 million and $0 million, respectively, of collateral related to derivatives with contingent provisions that are in a net liability position. If all of the contingent features underlying these instruments were fully triggered as of December 31, 2011 and 2010, SCE&G would be required to post an additional $23.0 million and $34.2 million, respectively, of collateral to its counterparties. The aggregate fair value of all derivative instruments with contingent provisions that are in a net liability position as of December 31, 2011 and 2010, are $68.0 million and $34.2 million, respectively.

7. FAIR VALUE MEASUREMENTS, INCLUDING DERIVATIVES

SCE&G values commodity derivative assets and liabilities using unadjusted NYMEX prices to determine fair value, and considers such measure of fair value to be Level 1 for exchange traded instruments and Level 2 for over-the-counter instruments. SCE&G's interest rate swap agreements are valued using discounted cash flow models with independently sourced data. Fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

	Fair Value Measurements Using	
Millions of dollars	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**
As of December 31, 2011		
Assets-Interest rate contracts	-	$1
Liabilities-Interest rate contracts	-	68
As of December 31, 2010		
Assets-Interest rate contracts	-	$4
Commodity contracts	$1	-
Liabilities-Interest rate contracts	-	34

There were no fair value measurements based on significant unobservable inputs (Level 3) for either period presented. In addition, there were no transfers of fair value amounts into or out of Levels 1 and 2 during any period presented.

Financial instruments for which the carrying amount may not equal estimated fair value at December 31, 2011 and December 31, 2010 were as follows:

	December 31, 2011		December 31, 2010	
Millions of dollars	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$2,925.7	$3,565.1	$2,726.0	$2,948.8

Fair values of long-term debt are based on quoted market prices of the instruments or similar instruments. For debt instruments for which no quoted market prices are available, fair values are based on net present value calculations. Carrying values reflect the fair values of interest rate swaps based on discounted cash flow models with independently sourced data. Early settlement of long-term debt may not be possible or may not be considered prudent.

Potential taxes and other expenses that would be incurred in an actual sale or settlement have not been considered.

8. EMPLOYEE BENEFIT PLANS AND EQUITY COMPENSATION PLAN

Pension and Other Postretirement Benefit Plans

SCE&G participates in SCANA’s noncontributory defined benefit pension plan, which covers substantially all regular, full-time employees. SCANA’s policy has been to fund the plan to the extent permitted by applicable federal income tax regulations, as determined by an independent actuary.

SCANA’s pension plan provides benefits under a cash balance formula for employees hired before January 1, 2000 who elected that option and for all employees hired on or after January 1, 2000. Under the cash balance formula, benefits accumulate as a result of compensation credits and interest credits. Employees hired before January 1, 2000 who elected to remain under the final average pay formula earn benefits based on years of credited service and the employee’s average annual base earnings received during the last three years of employment.

In addition to pension benefits, SCE&G participates in SCANA’s unfunded postretirement health care and life insurance programs which provide benefits to certain active and retired employees. Retirees share in a portion of their medical care cost. SCANA provides life insurance benefits to retirees at no charge. The costs of postretirement benefits other than pensions are accrued during the years the employees render the services necessary to be eligible for these benefits.

Changes in Benefit Obligations

The measurement date used to determine pension and other postretirement benefit obligations is December 31. Data related to the changes in the projected benefit obligation for retirement benefits and the accumulated benefit obligation for other postretirement benefits are presented below.

	Pension Benefits		Other Postretirement Benefits	
Millions of dollars	**2011**	**2010**	**2011**	**2010**
Benefit obligation, January 1	$687.8	$667.4	$171.0	$170.8
Service cost	14.7	14.0	3.3	3.1
Interest cost	37.0	41.2	9.3	9.1
Plan participants’ contributions	-	-	2.4	2.4
Actuarial (gain) loss	2.6	(0.6)	5.5	(1.1)
Benefits paid	(37.1)	(34.2)	(11.0)	(11.1)
Amounts funded to parent	-	-	(2.8)	(2.2)
Benefit obligation, December 31	$705.0	$687.8	$177.7	$171.0

The accumulated benefit obligation for retirement benefits was $666.7 million at the end of 2011 and $649.0 million at the end of 2010. The accumulated retirement benefit obligation differs from the projected retirement benefit obligation above in that it reflects no assumptions about future compensation levels.

Significant assumptions used to determine the above benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Annual discount rate used to determine benefit obligation	5.25%	5.56%	5.35%	5.72%
Assumed annual rate of future salary increases for projected benefit obligation	4.00%	4.00%	4.00%	4.00%

An 8.2% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2012. The rate was assumed to decrease gradually to 5.0% for 2020 and to remain at that level thereafter.

A one percent increase in the assumed health care cost trend rate would increase the postretirement benefit obligation at December 31, 2011 by $1.4 million and at December 31, 2010 by $1.4 million. A one percent decrease in the assumed health care cost trend rate would decrease the postretirement benefit obligation at December 31, 2011 by $1.2 million and at December 31, 2010 by $1.3 million.

Funded Status

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2011	2010	2011	2010
Fair value of plan assets	$695.3	$745.2	-	-
Benefit obligations	705.0	687.8	$177.7	$171.0
Funded status (liability)	$(9.7)	$57.4	$(177.7)	$(171.0)

Amounts recognized on the balance sheets consist of:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2011	2010	2011	2010
Noncurrent asset	-	$57.4	-	-
Current liability	-	-	$(8.3)	$(8.9)
Noncurrent liability	$ (9.7)	-	(169.4)	(162.1)

Amounts recognized in accumulated other comprehensive income (a component of common equity) as of December 31, 2011 and 2010 were as follows:

Millions of Dollars	Pension Benefits		Other Postretirement Benefits	
December 31,	2011	2010	2011	2010
Net actuarial loss	$2.4	$1.8	$0.4	$0.3
Prior service cost	0.3	0.4	0.1	0.1
Total	$2.7	$2.2	$0.5	$0.4

In connection with the joint ownership of Summer Station, as of December 31, 2011 and 2010, SCE&G recorded within deferred debits $19.7 million and $13.0 million, respectively, attributable to Santee Cooper's portion of shared pension costs. As of December 31, 2011 and 2010, SCE&G also recorded within deferred debits $11.4 million and $10.7 million, respectively, from Santee Cooper, representing its portion of the unfunded net postretirement benefit obligation.

Changes in Fair Value of Plan Assets

Millions of dollars	Pension Benefits 2011	Pension Benefits 2010
Fair value of plan assets, January 1	$745.2	$660.7
Actual return on plan assets	(12.8)	118.7
Benefits paid	(37.1)	(34.2)
Fair value of plan assets, December 31	$695.3	$745.2

Investment Policies and Strategies

The assets of the pension plan are invested in accordance with the objectives of (1) fully funding the actuarial accrued liability for the pension plan, (2) maximizing return within reasonable and prudent levels of risk in order to minimize contributions, and (3) maintaining sufficient liquidity to meet benefit payment obligations on a timely basis. The pension plan operates with several risk and control procedures, including ongoing reviews of liabilities, investment objectives, investment managers and performance expectations. Transactions involving certain types of investments are prohibited. Equity securities held by the pension plan during the periods presented did not include SCANA common stock.

The pension plan asset allocation at December 31, 2011 and 2010 and the target allocation for 2012 are as follows:

	Percentage of Plan Assets		
	Target Allocation	At December 31,	
Asset Category	2012	2011	2010
Equity Securities	65%	65%	68%
Debt Securities	35%	35%	32%

For 2012, the expected long-term rate of return on assets will be 8.25%. In developing the expected long-term rate of return assumptions, management evaluates the pension plan's historical cumulative actual returns over several periods, and assumes an asset allocation of 65% with equity managers and 35% with fixed income managers. Management regularly reviews such allocations and periodically rebalances the portfolio when considered appropriate.

Fair Value Measurements

Assets held by the pension plan are measured at fair value as described below. Assets are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. At December 31, 2011 and 2010, fair value measurements, and the level within the fair value hierarchy in which the measurements fall, were as follows:

		Fair Value Measurements at Reporting Date Using		
Millions of dollars	December 31, 2011	Quoted Market Prices in Active Market for Identical Assets/Liabilities (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Other Unobservable Inputs (Level 3)
December 31, 2011				
Common stock	$298	$298		
Preferred stock	1	1		
Mutual funds	169	19	$150	
Short-term investment vehicles	21		21	
Government agency securities	29		29	
Corporate debt securities	47		47	
Loans secured by mortgages	11		11	
Municipals	4		4	

Common collective trusts	34		34	
Limited partnerships	21		21	
Multi-strategy hedge funds	60			$60
	$695	$318	$317	$60
December 31, 2010				
Common stock	$331	$331		
Mutual funds	187	22	$165	
Short-term investment vehicles	17		17	
Government agency securities	47		47	
Corporate debt securities	46		46	
Loans secured by mortgages	8		8	
Municipals	3		3	
Common collective trusts	41		41	
Limited partnerships	24	1	23	
Multi-strategy hedge funds	41			$41
	$745	$354	$350	$41

The Pension Plan values common stock and certain mutual funds, where applicable, using unadjusted quoted prices from a national stock exchange, such as New York Stock Exchange (NYSE) and the NASDAQ Stock Market, Inc (NASDAQ), where the securities are actively traded. Other mutual funds, common collective trusts and limited partnerships are valued using the observable prices of the underlying fund assets based on trade data for identical or similar securities or from a national stock exchange for similar assets or broker quotes. Short-term investment vehicles are funds that invest in short-term fixed income instruments and are valued using observable prices of the underlying fund assets based on trade data for identical or similar securities. Government agency securities are valued using quoted market prices or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Corporate debt securities and municipals are valued based on recently executed transactions, using quoted market prices, or based on models using observable inputs from market sources such as external prices or spreads or benchmarked thereto. Loans secured by mortgages are valued using observable prices based on trade data for identical or comparable instruments. Hedge funds are invested in a hedge fund of funds partnership that invests directly in multiple hedge fund strategies that are not traded on exchanges and do not trade on a daily basis. The valuation of this multi-strategy hedge fund is estimated based on the net asset value of the underlying hedge fund strategies using consistent valuation guidelines that account for variations that may impact their fair value. The estimated fair value is the price at which redemptions and subscriptions occur.

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)	
Millions of dollars	**2011**	**2010**
Beginning Balance	$41	$12
Unrealized gains (losses) included in changes in net assets	(1)	2
Purchases, issuances, and settlements	20	27
Transfers in or out of Level 3	-	-
Ending Balance	$60	$41

Expected Cash Flows

The total benefits expected to be paid from the pension plan or from SCE&G's assets for the other postretirement benefits plan, respectively, are as follows:

Expected Benefit Payments

Millions of dollars	Pension Benefits	Other Postretirement Benefits* Excluding Medicare Subsidy	Other Postretirement Benefits* Including Medicare Subsidy
2012	$73.4	$8.5	$8.3
2013	66.8	9.0	8.8
2014	61.8	9.7	9.5
2015	63.3	10.3	10.0
2016	65.5	10.8	10.5
2017 - 2021	315.5	60.2	59.2

* Net of participant contributions

Pension Plan Contributions

The pension trust is adequately funded under current regulations. No contributions have been required since 1997, and SCE&G does not anticipate making significant contributions to the pension plan until after 2012.

Net Periodic Benefit Cost (Income)

SCE&G records net periodic benefit cost (income) utilizing beginning of the year assumptions. Disclosures required for these plans are set forth in the following tables.

Components of Net Periodic Benefit Cost

Millions of dollars	Pension Benefits 2011	2010	2009	Other Postretirement Benefits 2011	2010	2009
Service cost	$14.7	$14.0	$11.9	$3.3	$3.1	$2.8
Interest cost	37.0	41.2	42.0	9.3	9.1	9.2
Expected return on assets	(54.2)	(58.0)	(48.2)	n/a	n/a	n/a
Prior service cost amortization	6.0	6.6	6.6	0.8	0.8	0.7
Amortization of actuarial losses	10.4	15.1	22.3	0.3	-	-
Transition amount amortization	-	-	-	(0.1)	(0.1)	(0.1)
Net periodic benefit cost	$13.9	$18.9	$34.6	$13.6	$12.9	$12.6

In February 2009, SCE&G was granted accounting orders by the SCPSC which allowed it to mitigate a significant portion of increased pension cost by deferring as a regulatory asset the amount of pension cost above that which was included in then current cost of service rates for its retail electric and gas distribution regulated operations. In July 2010, upon the new retail electric base rates becoming effective, SCE&G began deferring, as a regulatory asset, all pension cost related to its regulated retail electric operations that otherwise would have been charged to expense. In November 2010, upon the updated gas rates becoming effective under the RSA, SCE&G began deferring, as a regulatory asset, all pension cost related to its regulated natural gas operations that otherwise would have been charged to expense.

Other changes in plan assets and benefit obligations recognized in other comprehensive income were as follows:

Millions of dollars	Pension Benefits 2011	2010	2009	Other Postretirement Benefits 2011	2010	2009
Current year actuarial (gain)/loss	$0.7	$(28.9)	$(9.8)	$0.1	$-	$0.1
Amortization of actuarial losses	(0.1)	(1.8)	(3.6)	-	-	-
Amortization of prior service cost	(0.1)	-	-	-	-	-
Prior service cost OCI adjustment	-	0.4	-	-	-	-

Amortization of transition obligation	-	-	-	-	(0.1)	-
Total recognized in other comprehensive income	$0.5	$(30.3)	$(13.4)	$0.1	$(0.1)	$0.1

Significant Assumptions Used in Determining Net Periodic Benefit Cost

	Pension Benefits			Other Postretirement Benefits		
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
Discount rate	5.56%	5.75%	6.45%	$5.72%	5.90%	6.45%
Expected return on plan assets	8.25%	8.50%	8.50%	n/a	n/a	n/a
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%	4.00%
Health care cost trend rate	n/a	n/a	n/a	8.00%	8.50%	8.00%
Ultimate health care cost trend rate	n/a	n/a	n/a	5.00%	5.00%	5.00%
Year achieved	n/a	n/a	n/a	2017	2017	2015

The estimated amounts to be amortized from accumulated other comprehensive income into net periodic benefit cost in 2012 are as follows:

Millions of Dollars	Pension Benefits	Other Postretirement Benefits
Actuarial loss	$0.1	-
Prior service cost	0.1	-
Total	$0.2	-

Other postretirement benefit costs are subject to annual per capita limits pursuant to plan design. As a result, the effect of a one-percent increase or decrease in the assumed health care cost trend rate on total service and interest cost is less than $100,000.

Stock Purchase Savings Plan

SCE&G participates in a SCANA-sponsored defined contribution plan in which eligible employees may participate. Eligible employees may defer up to 25% of eligible earnings subject to certain limits and may diversify their investments. Employee deferrals are fully vested and nonforfeitable at all times. SCE&G provides 100% matching contributions up to 6% of an employee's eligible earnings. Total matching contributions made to the plan for 2011, 2010 and 2009 were $17.3 million, $16.6 million and $16.6 million, respectively, and were made in the form of SCANA common stock.

9. SHARE-BASED COMPENSATION

SCE&G participates in the Plan which provides for grants of nonqualified and incentive stock options, stock appreciation rights, restricted stock, performance shares, performance units and restricted stock units to certain key employees and non-employee directors. The Plan currently authorizes the issuance of up to five million shares of SCANA's common stock, no more than one million of which may be granted in the form of restricted stock.

Compensation costs related to share-based payment transactions are required to be recognized in the financial statements. With limited exceptions, including those liability awards discussed below, compensation cost is measured based on the grant-date fair value of the instruments issued and is recognized over the period that an employee provides service in exchange for the award.

Liability Awards

The 2009-2011, 2010-2012, and 2011-2013 performance cycles provide for performance measurement and award determination on an annual basis, with payment of awards being deferred until after the end of the three-year performance cycle. In each of the performance cycles, 20% of the performance award was granted in the form of restricted share units, which are liability awards payable in cash and are subject to forfeiture in the event of retirement or termination of employment prior to the end of the cycle, subject to exceptions for death, disability or change in control. The remaining 80% of the award was made in performance shares. Each performance share has a value that is equal to, and changes with, the value of a share of SCANA common stock, and dividend equivalents are accrued on the performance shares. Payout of performance share awards was determined by SCANA's performance against pre-determined measures of total shareholder return (TSR) as compared to a peer group of utilities (weighted 50%) and growth in "GAAP-adjusted net earnings per share from operations" (weighted 50%). Payouts under the 2009-2011 performance cycle were earned for each year that performance goals were met during the three-year cycle. Awards were designated as target shares of SCANA common stock and were paid in cash at SCANA's discretion in February 2012.

Compensation cost of all these liability awards is recognized over their respective three-year performance periods based on the estimated fair value of the award, which is periodically updated based on expected ultimate cash payout, and is reduced by estimated forfeitures. Cash-settled liabilities related to similar prior programs were paid totaling $2.5 million in 2011, $2.4 million in 2010 and $1.7 million in 2009.

Fair value adjustments for performance awards resulted in compensation expense recognized in the statements of income totaling $4.0 million in 2011, $9.0 million in 2010 and $4.5 million in 2009. Fair value adjustments resulted in capitalized compensation costs of $0.2 million in 2011, $2.2 million in 2010 and $0.9 million in 2009.

Equity Awards

In the 2008-2010 performance cycle, 20% of the performance award was granted in the form of restricted (nonvested) shares rather than restricted share units. A summary of activity related to these nonvested shares follows:

Nonvested Shares	Shares	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2009	74,588	$37.33
Forfeited	(2,399)	37.33
Nonvested at December 31, 2009	72,189	37.33
Vested	(72,189	37.33
Nonvested at December 31, 2010	-	

Nonvested shares were granted at a price corresponding to the opening price of SCANA common stock on the date of the grant. As of December 31, 2010 all compensation cost related to nonvested share-based compensation arrangements under the Plan had been recognized. SCE&G expensed compensation costs for nonvested shares of $0.1 million in each of 2010 and 2009. Tax benefits and capitalized compensation costs in 2010 and 2009 were not significant.

A summary of activity related to nonqualified stock options follows:

Stock Options	Number of Options	Weighted Average Exercise Price
Outstanding-January 1, 2009	106,464	$27.44
Exercised	(2,875)	27.50
Outstanding-December 31, 2009	103,589	27.44
Exercised	(53,246)	27.40
Outstanding-December 31, 2010	50,343	27.49
Exercised	(40,267)	27.48
Outstanding-December 31, 2011	10,076	27.52

No stock options were granted or forfeited and all options were fully vested during the periods presented. The options expire ten years after their respective grant dates and all options currently outstanding will expire in 2012. At December 31, 2011, all outstanding options were currently exercisable at a price of $27.52, and had a weighted-average remaining contractual life of less than one year.

The exercise of stock options during the periods presented were satisfied using original issue shares. For the years ended December 31, 2011, 2010 and 2009, cash realized upon the exercise of options and related tax benefits were not significant.

10. COMMITMENTS AND CONTINGENCIES

Nuclear Insurance

Under Price-Anderson, SCE&G (for itself and on behalf of Santee-Cooper, a one-third owner of Summer Station Unit 1) maintains agreements of indemnity with the United States Nuclear Regulatory Commission (NRC) that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at SCE&G’s nuclear power plant. Price-Anderson provides funds up to $12.6 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $375 million by ANI with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. Each reactor licensee is currently liable for up to $117.5 million per reactor owned for each nuclear incident occurring at any reactor in the United States, provided that not more than $17.5 million of the liability per reactor would be assessed per year. SCE&G's maximum assessment, based on its two-thirds ownership of Summer Station Unit 1, would be $78.3 million per incident, but not more than $11.7 million per year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years.

SCE&G currently maintains policies (for itself and on behalf of Santee Cooper) with Nuclear Electric Insurance Limited (NEIL). The policies provide coverage to the nuclear facility for property damage and outage costs up to $2.75 billion. In addition, a builder’s risk insurance policy has been purchased from NEIL for the construction of the New Units. This policy provides the Owners up to $500 million in limits of accidental property damage occurring during construction. All of the NEIL policies permit retrospective assessments under certain conditions to cover insurer's losses. Based on the current annual premiums, SCE&G's portion of the prospective premium assessment would not exceed $37.3 million.

To the extent that insurable claims for property damage, decontamination, repair and replacement and other costs and expenses arising from a nuclear incident at Summer Station Unit 1 exceed the policy limits of insurance, or to the extent such insurance becomes unavailable in the future, and to the extent that SCE&G rates would not recover the cost of any purchased replacement power, SCE&G will retain the risk of loss as a self-insurer. SCE&G has no reason to anticipate a serious nuclear incident. However, if such an incident were to occur, it likely would have a material impact on the SCE&G's results of operations, cash flows and financial position.

Environmental

In December 2009, the United States Environmental Protection Agency (EPA) issued a final finding that atmospheric concentrations of GHG endanger public health and welfare within the meaning of Section 202(a) of the Clean Air Act, as amended (CAA). The rule, which became effective in January 2010, enables the EPA to regulate GHG emissions under the CAA. The EPA has committed to issue new rules regulating such emissions in 2012. SCE&G expects that any costs incurred to comply with Greenhouse Gas (GHG) emission requirements will be recoverable through rates.

In 2005, the EPA issued the Clean Air Interstate Rule (CAIR), which required the District of Columbia and 28 states, including South Carolina, to reduce nitrogen oxide and sulfur dioxide emissions in order to attain mandated state levels. CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for nitrogen oxide and beginning in 2010 and 2015, respectively, for sulfur dioxide. SCE&G determined that additional air quality controls would be needed to meet the CAIR requirements. On July 6, 2011 the EPA issued the Cross-State Air Pollution Rule (CSAPR). This rule replaced CAIR and the Clean Air Transport Rule proposed in July 2010 and aimed at addressing power plant emissions that may contribute to air pollution in other states. CSAPR requires states in the eastern United States to reduce power plant emissions, specifically sulfur dioxide and nitrogen oxide. On December 30, 2011, the United States Court of Appeals for the District of Columbia issued an order staying CSAPR and reinstating CAIR pending resolution of an appeal of CSAPR. Air quality control installations that SCE&G has already completed should assist SCE&G in complying with the Cross-State Air Pollution Rule and the reinstated CAIR. SCE&G will continue to pursue strategies to comply with all applicable environmental regulations. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

In 2005, the EPA issued the Clean Air Mercury Rule (CAMR) which established a mercury emissions cap and trade program for coal-fired power plants. Numerous parties challenged the rule and, on February 8, 2008, the United States Circuit Court for the District of Columbia vacated the rule for electric utility steam generating units. In March 2011, the EPA proposed new standards for mercury and other specified air pollutants. The rule, which becomes effective on April 16, 2012, provides up to four years for facilities to meet the standards. The rule is currently being evaluated by SCE&G. Any costs incurred to comply with this rule or other rules issued by the EPA in the future are expected to be recoverable through rates.

SCE&G has been named, along with 53 others, by the EPA as a Potentially Responsible Party (PRP) at the Alternate Energy Resources, Inc. (AER) Superfund site located in Augusta, Georgia. The PRPs funded a Remedial Investigation and Risk Assessment which was completed and approved by the EPA and funded a Feasibility Study that was completed in 2010. A clean-up cost has been estimated and the PRPs have agreed to an allocation of those costs based primarily on volume and type of material each PRP sent to the site. SCE&G's allocation did not have a material impact on its results of operations, cash flows or financial condition.

SCE&G maintains an environmental assessment program to identify and evaluate its current and former operations sites that could require environmental clean-up. As site assessments are initiated, estimates are made of the amount of expenditures, if any, deemed necessary to investigate and remediate each site. These estimates are refined as additional information becomes available; therefore, actual expenditures could differ significantly from the original estimates. Amounts estimated and accrued to date for site assessments and clean-up relate solely to regulated operations. SCE&G defers site assessment and cleanup costs and expects to recover them through rates.

SCE&G is responsible for four decommissioned MGP sites in South Carolina which contain residues of by-product chemicals. These sites are in various stages of investigation, remediation and monitoring under work plans approved by South Carolina Department of Health and Environmental Control (DHEC). SCE&G anticipates that major remediation activities at these sites will continue until 2014 and will cost an additional $8.3 million. SCE&G expects to recover any cost arising from the remediation of MGP sites through rates and insurance settlements. At December 31, 2011, deferred amounts, net of amounts previously recovered through rates and insurance settlements, totaled $24.9 million and are included in regulatory assets.

Claims and Litigation

In May 2004, a purported class action lawsuit currently styled as Douglas E. Grosseto and Mark Rudd, individually and on behalf of other persons similarly situated v. South Carolina Electric & Gas Company and SCANA Communications, Inc. was filed in South Carolina's Circuit Court of Common Pleas for the Ninth Judicial Circuit. The plaintiffs alleged that SCE&G made improper use of certain electric transmission easements and rights-of-way by allowing fiber optic communication lines and/or wireless communication equipment to transmit communications other than SCE&G's electricity related internal communications and asserted causes of action for unjust enrichment, trespass, injunction and declaratory judgment. While SCE&G and SCANA Communications, Inc. (SCI)believe their actions were consistent with governing law and the applicable documents granting easements and rights-of-way, this case, with Circuit Court approval in August 2010, has been settled as to all easements and rights of ways currently containing fiber optic communications lines in South Carolina. This settlement did not have a material impact on SCE&G's results of operations, cash flows or financial condition.

SCE&G is also engaged in various other claims and litigation incidental to its business operations which management anticipates will be resolved without a material impact on SCE&G's results of operations, cash flows or financial condition.

Operating Lease Commitments

SCE&G is obligated under various operating leases with respect to office space, furniture and equipment. Leases expire at various dates through 2057. Rent expense totaled approximately $10.8 million in 2011, $9.3 million in 2010 and $16.5 million in 2009. Future minimum rental payments under such leases are as follows:

	Millions of dollars
2012	$7
2013	6
2014	2
2015	1
2016	-
Thereafter	21
Total	$37

Purchase Commitments

SCE&G is obligated for purchase commitments that expire at various dates through 2034. Amounts expended for coal supply, nuclear fuel contracts, construction projects and other commitments totaled $624.5 million in 2011, $556.8 million in 2010 and $604.3 million in 2009. Future payments under such purchase commitments are as follows:

	Millions of dollars
2012	$1,362
2013	916
2014	836
2015	767
2016	773
Thereafter	1,038
Total	$5,692

Asset Retirement Obligations

SCE&G recognizes a liability for the fair value of an ARO when incurred if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information exists, but such uncertainty is not a basis upon which to avoid liability recognition.

The legal obligations associated with the retirement of long-lived tangible assets that result from their acquisition, construction, development and normal operation relate primarily to SCE&G's regulated utility operations. As of December 31, 2011, SCE&G has recorded an ARO of approximately $124 million for nuclear plant decommissioning (see Note 1) and an ARO of approximately $303 million for other conditional obligations related to generation, transmission and distribution properties, including gas pipelines. All of the amounts recorded are based upon estimates which are subject to varying degrees of imprecision, particularly since such payments will be made many years in the future.

A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations is as follows:

Millions of dollars	2011	2010
Beginning balance	$457	$439
Liabilities incurred	-	1
Liabilities settled	-	(1)
Accretion expense	21	23
Revisions in estimated cash flows	(51)	(5)
Ending Balance	$427	$457

11. AFFILIATED TRANSACTIONS

Carolina Gas Transmission Corporation (CGT) transports natural gas to SCE&G to serve retail gas customers and certain electric generation requirements. Such purchases totaled approximately $30.8 million in 2011, $32.0 million in 2010 and $30.4 million in 2009. SCE&G had approximately $2.5 million and $2.1 million payable to CGT for transportation services at December 31, 2011 and December 31, 2010, respectively.

SCE&G purchases natural gas and related pipeline capacity from SCANA Energy Marketing, Inc. (SEMI) to serve its retail gas customers and certain electric generation requirements. Such purchases totaled approximately $187.4 million in 2011, $182.5 million in 2010 and $160.8 million in 2009. SCE&G's payables to SEMI for such purposes were $13.2 million and $16.1 million as of December 31, 2011 and 2010, respectively.

SCE&G purchases all of the electric generation of Williams Station, which is owned by South Carolina Generating Company (GENCO), under a unit power sales agreement. SCE&G had approximately $6.5 million and $23.4 million, payable to GENCO for unit power purchases at December 31, 2011 and 2010, respectively. Such unit power purchases, which are included in "Purchased power," amounted to approximately $184.4 million and $215.8 million for the year to December 31, 2011 and 2010, respectively.

SCE&G owns 40% of Canadys Refined Coal, LLC and 10% of Cope Refined Coal, LLC, both involved in the manufacturing and selling of refined coal to reduce emissions. SCE&G accounts for these investments using the equity method. SCE&G's receivables from these affiliates were $8.5 million at December 31, 2011 and insignificant at December 31, 2010. SCE&G's payables to these affiliates were $8.6 million at December 31, 2011 and insignificant at December 31, 2010. SCE&G's total purchases were $123.8 million in 2011 and $97.3 million in 2010. SCE&G's total sales were $123.3 million in 2011 and $96.9 million in 2010.

SCE&G participates in a utility money pool. Money pool borrowings and investments bear interest at short-term market rates. SCE&G's interest income and expense from money pool transactions was not significant for any period presented. At December 31, 2011 and 2010, SCE&G had no outstanding money pool borrowings due to an affiliate in 2011 or 2010, respectively.

An affiliate processes and pays invoices for SCE&G and is reimbursed by them. SCE&G owed $38.3 million and $37.8 million to the affiliate at December 31, 2011 and 2010, respectively, for invoices paid by the affiliate on behalf of SCE&G.

12. SEGMENT OF BUSINESS INFORMATION

SCE&G's reportable segments are listed in the following table. SCE&G uses operating income to measure profitability for its regulated operations. Therefore, earnings available to common shareholders are not allocated to the Electric Operations and gas segments. Intersegment revenues were not significant.

Electric Operations is primarily engaged in the generation, transmission, and distribution of electricity, and is regulated by the SCPSC and FERC. Gas Distribution is engaged in the purchase and sale, primarily at retail, of natural gas, and is regulated by the SCPSC.

Disclosure of Reportable Segments (Millions of dollars)

	Electric Operations	Gas Distribution	Adjustments/ Eliminations	Total
2011				
External Revenue	2,432	387	-	2,819
Operating Income	581	40	(2)	619
Interest Expense	3	-	181	184
Depreciation and Amortization	252	24	(9)	267
Segment Assets	7,578	622	2,202	10,402
Expenditures for Assets	795	60	(7)	848
Deferred Tax Assets	2	n/a	3	5

2010				
External Revenue	$2,367	$441	$-	$2,808
Intersegment Revenue	-	1	(1)	-
Operating Income	521	52	(2)	571
Interest Expense	2	-	165	167
Depreciation and Amortization	246	22	(11)	257
Segment Assets	7,232	590	2,116	9,938
Expenditures for Assets	738	39	(24)	753
Deferred Tax Assets	n/a	n/a	13	13
2009				
External Revenue	$2,149	$420	-	$2,569
Intersegment Revenue	-	2	$(2)	-
Operating Income	488	43	(1)	530
Interest Expense	1	-	148	149
Depreciation and Amortization	232	21	(10)	243
Segment Assets	6,657	558	1,966	9,181
Expenditures for Assets	749	39	(100)	688
Deferred Tax Assets	n/a	n/a	n/a	n/a

Management uses operating income to measure segment profitability for regulated operations and evaluates utility plant, net, for its segments. As a result, SCE&G does not allocate interest charges, income tax expense or assets other than utility plant to its segments. Interest income is not reported by segment and is not material. SCE&G’s deferred tax assets are netted with deferred tax liabilities for reporting purposes.

The financial statements report operating revenues which are comprised of the reportable segments. Revenues from non-reportable segments are included in Other Income. Therefore, the adjustments to total operating revenues remove revenues from non-reportable segments. Segment Assets include utility plant, net for all reportable segments. As a result, adjustments to assets include non-utility plant and non-fixed assets for the segments. Adjustments to Interest Expense and Deferred Tax Assets include amounts that are not allocated to the segments. Expenditures for Assets are adjusted for revisions to estimated cash flows related to asset retirement obligations, and totals not allocated to other segments.

13. QUARTERLY FINANCIAL DATA (UNAUDITED)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Annual
2011 Millions of dollars					
Total operating revenues	$704	$691	$797	$627	$2,819
Operating income	142	129	211	137	619
Net income attributable to SCE&G	68	59	117	62	306
2010 Millions of dollars					
Total operating revenues	$720	$648	$777	$663	$2,808
Operating income	117	129	190	135	571
Net income attributable to SCE&G	62	60	106	62	290

SUPPLEMENTAL CASH FLOW INFORMATION

Cash paid for interest: $158 million and $156 million in 2011 and 2010, respectively (net of capitalized interest of $7 million and $9 million in 2011 and 2010, respectively).

Cash paid for income taxes: $- million and $28 million in 2011 and 2010, respectively.
Noncash investing and Financing Activities- Accrued construction expenditures: $73 million and $168 million in 2011 and 2010, respectively.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - TOTAL ELECTRIC
12 MONTHS ENDED DECEMBER 31, 2011

Line No.	Description	Regulatory Per Books ($000's)	Pro-Forma Adjustments ($000's)	Total As Adjusted ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,432,190	(121,495)	2,310,695
2	Operating Expenses			
3	O&M Expenses - Fuel	932,607	(970)	931,637
4	O&M Expenses - Other	509,288	33,775	543,063
5	Depreciation & Amortization Expenses	252,861	19,015	271,876
6	Taxes Other Than Income	159,836	(49)	159,787
7	Total Income Taxes	130,595	(52,845)	77,750
8	Total Operating Expenses	1,985,187	(1,073)	1,984,113
9	Operating Return	447,003	(120,422)	326,582
10	Customer Growth	586	(135)	451
11	Interest on Customer Deposits	(741)	-	(741)
12	Return	446,848	(120,557)	326,292
13	Rate Base			
14	Plant in Service	8,676,500	(60,023)	8,616,477
15	Reserve for Depreciation	3,273,727	(21,366)	3,252,361
16	Net Plant	5,402,773	(38,657)	5,364,116
17	Construction Work in Progress	1,448,028	(1,259,012)	189,016
18	Deferred Debits / Credits	(104,030)	67,704	(36,326)
19	Total Working Capital	102,992	4,054	107,046
20	Materials & Supplies	373,974	-	373,974
21	Accumulated Deferred Income Taxes	(977,144)	(3,852)	(980,996)
22	Total Rate Base	6,246,593	(1,229,763)	5,016,830
23	Rate of Return	7.15%		6.50%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
OPERATING EXPERIENCE - RETAIL ELECTRIC
12 MONTHS ENDED DECEMBER 31, 2011

Line No.	Description	Retail As Adjusted	Proposed Increase	Total After Proposed Increase
		($000's)		
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)
1	Operating Revenues	2,235,844	151,502	2,387,346
2	Operating Expenses			
3	O&M Expenses - Fuel	885,928		885,928
4	O&M Expenses - Other	526,919		526,919
5	Depreciation & Amortization Expenses	263,706		263,706
6	Taxes Other Than Income	155,034	687	155,721
7	Total Income Taxes	80,426	57,687	138,113
8	Total Operating Expenses	1,912,014	58,374	1,970,388
9	Operating Return	323,830	93,128	416,959
10	Customer Growth	451	82	533
11	Interest on Customer Deposits	(741)	-	(741)
12	Return	323,540	93,210	416,751
13	Rate Base			
14	Plant in Service	8,375,077	-	8,375,077
15	Reserve for Depreciation	3,154,676	-	3,154,676
16	Net Plant	5,220,401	-	5,220,401
17	Construction Work in Progress	182,885	-	182,885
18	Deferred Debits / Credits	(36,357)	-	(36,357)
19	Total Working Capital	101,310	-	101,310
20	Materials & Supplies	357,608	-	357,608
21	Accumulated Deferred Income Taxes	(956,712)	-	(956,712)
22	Total Rate Base	4,869,135	-	4,869,135
23	Rate of Return	6.64%		8.56%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
TOTAL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED DECEMBER 31, 2011

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	ADIT	DEFERRED DBT/CRDT	WORKING CASH
1	WAGES, BENEFITS & PAYROLL TAXES		10,181		722	(545)	(3,625)						1,273
2	INCENTIVE PAY		(6,078)		(395)	324	2,152						(760)
3	ANNUALIZE HEALTH CARE		2,128			(106)	(708)						266
4	REMOVE EMPLOYEE CLUBS		(413)	(143)		28	185	(4,793)	(1,630)				(52)
5	PROPERTY RETIREMENTS							(325)	(325)				
6	REMOVE NEW NUCLEAR AMOUNTS	(83,832)			(380)	(4,173)	(27,747)			(1,256,318)			
7	CWIP							2,694		(2,694)			
8	ANNUALIZE DEPRECIATION BASED ON CURRENT RATES			3,636		(182)	(1,209)		3,636				
9	PALMETTO CENTER SETTLEMENT		(686)			34	228						(86)
10	ADJUST PROPERTY TAXES				1,213	(61)	(403)						
11	ANNUALIZE INSURANCE EXPENSE		25			(1)	(8)						3
12	ENVIRONMENTAL REMEDIATION RECOVERY		240			(12)	(80)						30
13	EDISON ELECTRIC INSTITUTE MEMBERSHIP		200			(10)	(66)						25
14	CAYCE BUSINESS LICENSE FEES				(238)	12	79						
15	TAX EFFECT OF ANNUALIZED INTEREST					1,755	11,673						
16	REMOVE DSM AMOUNTS	(5,660)	(253)		(26)	(269)	(1,789)						(31)
17	WATEREE SCRUBBER DEFERRAL - AMORTIZATION			4,918		(246)	(1,635)						
18	WATEREE SCRUBBER - CURRENT EXPENSE		939	12,046		(649)	(4,318)		12,046				117
19	WATEREE SCRUBBER - RB ADJUSTMENT											12,149	
20	PENSION DEFERRAL - AMORTIZATION		4,866			(243)	(1,618)						608
21	PENSION - CURRENT EXPENSE		12,526			(626)	(4,165)						1,566
22	PENSION - RB ADJUSTMENT											33,049	
23	AMORTIZE CAPACITY PURCHASES		1,230			(62)	(409)						
24	CAPACITY PURCHASE O&M ADJ		(851)			43	283						

SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCOUNTING & PRO FORMA ADJUSTMENTS
TOTAL ELECTRIC
OPERATING EXPERIENCE
TWELVE MONTHS ENDED DECEMBER 31, 2011

ADJ. #	DESCRIPTION	REVENUES	O & M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX @ 5%	FEDERAL INCOME TAX @ 35%	PLANT IN SERVICE	ACCUM. DEPREC.	CWIP	ADIT	DEFERRED DBT/CRDT	WORKING CASH
25	AMORTIZE $25M WEATHER REFUND OVERAGE and EIZ CREDIT	(2,000)			(9)	(100)	(662)						
26	REMOVE OFF SYSTEM SALES CONTRACT	(30,003)			(136)	(1,493)	(9,931)						
27	STORM RESERVE		6,054			(303)	(2,013)						757
28	T&D INSURANCE PREMIUM		3,058			(153)	(1,017)						382
29	AMORTIZE ECONOMIC DEVELOPMENT GRANTS		660			(33)	(219)						83
30	AMORTIZE NEW RATE CASE EXPENSES		233			(12)	(77)						29
31	CANADYS UNIT 1 RETIREMENT		(1,931)	(1,000)	(800)	187	1,240	(50,653)	(28,147)		(3,852)	22,506	(241)
32	URQUHART UNIT 3 COAL EQUIPMENT RETIREMENT		(1,632)	(442)		104	690	(6,946)	(6,946)				(204)
33	WRITEOFF RECOVERY		535			(27)	(178)						67
34	VCS OUTAGE ACCRUAL MECHANISM		1,774			(89)	(590)						222
	TOTAL - ALL PROFORMAS	**(121,495)**	**32,805**	**19,015**	**(49)**	**(6,908)**	**(45,937)**	**(60,023)**	**(21,366)**	**(1,259,012)**	**(3,852)**	**67,704**	**4,054**

SOUTH CAROLINA ELECTRIC & GAS COMPANY
COMPUTATION OF PROPOSED INCREASE
RETAIL ELECTRIC OPERATIONS
12 MONTHS ENDED DECEMBER 31, 2011

Line No.	Description	Requested ($000's)
	(Col. 1)	(Col. 2)
1	Jurisdictional Rate Base	4,869,135
2	Required Rate of Return	8.56%
3	Required Return	416,798
4	Actual Return Earned	323,540
5	Required Increase to Return	93,258
6	Factor to Remove Customer Growth	1.001393
7	Additional Return Required from Revenue Increase	93,128
8	Composite Tax Factor	0.61470
9	Required Revenue Increase	151,502
10	Proposed Revenue Increase	151,502
	Additional Expenses	
11	Gross Receipts Tax @ .004537	687
12	State Income Tax @ 5%	7,541
13	Federal Income Tax @ 35%	50,146
14	Total Taxes	58,374
15	Additional Return	93,128
16	Additional Customer Growth	82
17	Total Additional Return	93,210
18	Earned Return	323,540
19	Total Return as Adjusted	416,750
20	Rate Base	4,869,135
21	Rate of Return	8.56%

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF FIXED ASSETS - ELECTRIC
AT DECEMBER 31, 2011

		($000's)			
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Gross Plant in Service				
1	Intangible Plant	66,268	-	66,268	64,411
2	Production	4,489,057	(56,997)	4,432,060	4,246,768
3	Transmission	910,496	419	910,915	871,702
4	Distribution	2,682,473	(43)	2,682,430	2,682,094
5	General	253,675	1,098	254,773	247,635
6	Common (1)	274,531	(4,500)	270,031	262,466
7	Total Gross Plant in Service	8,676,500	(60,023)	8,616,477	8,375,077
	Construction Work in Progress				
8	Production	1,327,929	(1,257,027)	70,902	67,938
9	Transmission	53,230	(441)	52,789	50,517
10	Distribution	33,644	(105)	33,539	33,535
11	General	28,666	(1,146)	27,520	26,749
12	Common (1)	4,559	(293)	4,266	4,146
13	Total Construction Work in Progress	1,448,028	(1,259,012)	189,016	182,885

(1) Electric Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
STATEMENT OF DEPRECIATION RESERVES - ELECTRIC
AT DECEMBER 31, 2011

			($000's)		
Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Intangible Plant	-	-	-	
2	Production	1,907,797	(21,989)	1,885,808	1,806,968
3	Transmission	270,605	325	270,930	259,283
4	Distribution	841,121	1,421	842,542	842,434
5	General	132,602	646	133,248	129,515
6	Common (1)	121,602	(1,769)	119,833	116,476
7	Total	3,273,727	(21,366)	3,252,361	3,154,676

(1) Electric Portion

Note: Depreciation for electric production plant is calculated and applied by generating unit location and specific plant account
All other electric plant depreciation is calculated and applied by plant account

SOUTH CAROLINA ELECTRIC & GAS COMPANY
MATERIALS AND SUPPLIES - ELECTRIC
AT DECEMBER 31, 2011

Line No.	Description	Regulatory Per Books ($000's)	Adjustments ($000's)	As Adjusted ($000's)	Allocated to Retail ($000's)
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
	Fuel Stock				
1	Nuclear	128,739	-	128,739	122,409
2	Fossil	130,254	-	130,254	123,849
3	Total Fuel Stock	258,993	-	258,993	246,258
4	Emission Allowances	3,854	-	3,854	3,693
5	Other Electric Materials and Supplies	111,127	-	111,127	107,657
6	Total	373,974	-	373,974	357,608

DEFERRED DEBITS / CREDITS - ELECTRIC
AT DECEMBER 31, 2011

Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
7	Post Employment Benefit	(84,089)	-	(84,089)	(81,819)
8	Deferred Environmental Costs	(251)	-	(251)	(248)
9	Storm Damage Reserve	(19,690)	-	(19,690)	(19,690)
10	Wateree Scrubber Deferral	-	12,149	12,149	11,641
11	Plant Retirements	-	22,506	22,506	21,565
12	Pension Deferral	-	33,049	33,049	32,193
13	Total	(104,030)	67,704	(36,326)	(36,357)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WORKING CAPITAL INVESTMENT - ELECTRIC
AT DECEMBER 31, 2011

Line No.	Description	Regulatory Per Books	Adjustments	As Adjusted	Allocated to Retail
		($000's)			
	(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)
1	Working Cash	149,261	4,054	153,315	147,036
2	Prepayments	58,536	-	58,536	58,081
3	Total Investor Advanced Funds	207,797	4,054	211,851	205,117
4	Less: Customer Deposits	(35,734)	-	(35,734)	(35,734)
5	Average Tax Accruals	(58,664)	-	(58,664)	(58,093)
6	Nuclear Refueling	(6,793)	-	(6,793)	(6,466)
7	Injuries and Damages	(3,614)	-	(3,614)	(3,512)
8	Total Working Capital	102,992	4,054	107,046	101,310

SOUTH CAROLINA ELECTRIC & GAS COMPANY
WEIGHTED COST OF CAPITAL
RETAIL ELECTRIC OPERATIONS
AT DECEMBER 31, 2011

Regulatory Capitalization for Electric Operations as of December 31, 2011

			As Adjusted		After Proposed Increase	
Description	Pro Forma Amount	Pro Forma Ratio	Pro Forma Embedded Cost/Rate	Overall Cost/Rate	Pro Forma Embedded Cost/Rate	Overall Cost/Rate
(Col. 1)	(Col. 2)	(Col. 3)	(Col. 4)	(Col. 5)	(Col. 6)	(Col. 7)
	$	%	%	%	%	%
Long Term Debt [1]	3,415,425,000	47.82%	5.97%	2.85%	5.97%	2.85%
Preferred Stock	100,000	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity [1]	3,726,171,908	52.18%	**7.26%**	3.79%	**10.95%**	5.71%
Total	7,141,696,908	100.00%		6.64%		8.56%

[1] Includes additional $48.7 Million Equity from Stock Plans and $11.6 Million Lag in Equity from Stock Plans and $500 Million LTD issuances

Exhibit No. ___ (JES-7)
Page 1 of 1

Exhibit C-7
Page 1 of 1

Summary of SCE&G Storm Reserve Activity Since Inception

Year	Beginning Balance	Collections	Storm Charges Applied to Reserve	Insurance Premiums Applied to Reserve	Tree Trimming/ Vegetation Management Applied to Reserve	Ending Balance
1996		$ 4,204,754				$ 4,204,754
1997	$ 4,204,754	$ 4,646,041				$ 8,850,795
1998	$ 8,850,795	$ 5,209,754				$ 14,060,549
1999	$ 14,060,549	$ 5,117,003	$ (3,895,456)			$ 15,282,096
2000	$ 15,282,096	$ 5,435,216	$ (152,213)			$ 20,565,099
2001	$ 20,565,099	$ 5,063,141				$ 25,628,240
2002	$ 25,628,240	$ 5,926,832				$ 31,555,072
2003	$ 31,555,072	$ 5,762,007				$ 37,317,079
2004	$ 37,317,079	$ 6,130,090	$ (10,920,633)			$ 32,526,536
2005	$ 32,526,536	$ 6,245,516	$ (307,008)			$ 38,465,044
2006	$ 38,465,044	$ 5,740,360	$ (89,851)			$ 44,115,553
2007	$ 44,115,553	$ 6,227,763		$ (1,360,001)		$ 48,983,315
2008	$ 48,983,315	$ 6,222,074	$ (2,542,236)	$ (2,801,197)	$ (1,953,239)	$ 47,908,717
2009	$ 47,908,717	$ 6,393,908		$ (3,046,197)	$ (6,995,375)	$ 44,261,053
2010	$ 44,261,053	$ 3,575,031	$ (153,322)	$ (2,911,350)	$ (6,461,763)	$ 38,309,649
2011	$ 38,309,649		$ (1,633,654)	$ (2,989,084)	$ (1,800,000)	$ 31,886,911
2012 **	$ 31,886,911			$ (1,783,931)		$ 30,102,980

** As of July 31, 2012